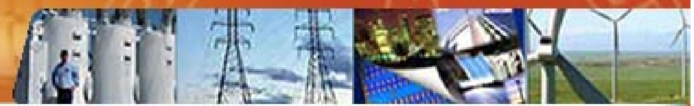
U.S. Department of Energy
Office of Electric Transmission and Distribution
Electric Distribution



Electric Distribution

Multi-Year Research, Development, Demonstration, and Deployment Technology Roadmap Plan: 2005-2009

December 2004

Office of Electric Transmission and Distribution
U.S. Department of Energy

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Executive Summary

The U.S. Department of Energy (DOE) Office of Electric Transmission and Distribution (OETD) engaged broad stakeholder participation in formulating a concerted, coordinated technology development plan in electric distribution for 2005 through 2009, with the focus of supporting accomplishment of the *Grid 2030 Vision*. The Vision called out the future electric system providing abundant, affordable, clean, efficient, and reliable electric power and with the functionality of "a fully automated power delivery network…ensuring a two-way flow of electricity and information between the power plants and appliances and all points in between." This document, *Electric Distribution Multi-Year Research, Development, Demonstration, and Deployment (RD^3) Technology Roadmap Plan: 2005-2009*, is the product of this engagement effort, and will be used by the OETD to help formulate its Distribution R&D budget and help set priorities on investments based on the recommended RD^3 activities. The *Roadmap Plan* implementation will be carried out through the OETD's Electric Distribution Transformation (EDT) Program, the GridWise Initiative, and to some degree, the GridWorks Initiative.

The OETD was established in August 2003, following the recommendation of the *National Transmission Grid Study (NTGS)*, which recommended that DOE commit its leadership to implementing the NTGS recommendations in order to meet the challenge areas outlined in the *National Energy Policy*, such as "modernize our energy infrastructure" and "increase energy security."

To accomplish this mission of leading a national effort to help modernize and expand America's electric delivery system to ensure a more reliable and robust electricity supply, as well as economic and national security, the OETD convened senior executives representing several key electric system stakeholder groups. This group of executives and their constituents jointly developed a common vision of the future electric system known as the *Grid 2030 Vision*. This was then followed by the development of the *National Electric Delivery Technologies Roadmap*, which identified and outlined critical technology areas for reaching the Vision.

This document is intended to focus on addressing one such critical technology area in the national roadmap document, i.e., "Distributed Sensors, Intelligence, Smart Controls, and Distributed Energy Resources." It defines the next level of details at individual program/project/activity levels to meet the critical technology need, spanning electric distribution infrastructure from distribution substations to customer-side load management. Additionally, this document also addresses RD^3 needs described in the *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* as pertaining to improved capabilities and tools for (distribution) system monitoring and management and demand response initiatives (for retail electric markets).

The multi-year plan development was based on a structured roadmap process from initial planning for engaging representative stakeholders, through conducting the Workshop, and through following up on the Workshop for additional input and feedback. The stakeholder engagement plan was developed and carried out with the help of the Workshop Planning Committee, comprising the group of eight session co-chairs (four utility members and one member each representing a system integrator, a technology supplier, an information technology provider, and a national laboratory), the Workshop organizer, and a DOE OETD Program Manager. The Planning Committee identified and solicited key representatives from all stakeholder groups for participation, with the two co-chairs of each of the four Technical Area sessions defining the subtopic areas of discussion, along with key information elements expected to be obtained from session participants.

During the Workshop, held August 17 and 18, 2004, two-co-chairs, one representing utility and one representing non-utility, guided and facilitated each Technical Area session discussion, grouped all relevant development into an RD^3 activity, forged consensus on the relative priorities of the activities, and designated a champion for each of the five-to-six activities that session participants agreed are the top priority. Each champion then summarized the discussion of the particular RD^3 activity and presented it to all Workshop attendees.

After the Workshop, each champion provided a written description of the RD^3 activity, based on the key information structure used during the Workshop, to the session co-chairs. The co-chairs sought and incorporated feedback on all descriptions from all session participants and sent their final version to the Workshop organizer and the DOE for incorporation into this document. Thus, this document is a culmination of contributions from all 83 participants in the Workshop.

The four Technical Area sessions are listed in Table 1, along with an outline of each session's discussion topics.

Table 1. Four Technical Areas and Their Respective Sub-topic Areas

Session 1	Session 2	Session 3	Session 4
Architecture & Communication Standards	**Monitoring & Load Management Technologies**	**Advanced Distribution Technologies & Operating Concepts**	**Modeling & Simulation**
• An overall architecture for a “system of systems” to support the transformation of the electrical distribution infrastructure • An architecture with defined participants, functions, and interdependence relations from a total system perspective	• Monitor distribution circuit for power quality and (incipient) fault locating/prediction/ prevention • Monitor and control industrial/commercial/ residential loads to participate in demand-side management (DSM) programs	• Diagnose conditions of the existing/aging distribution infrastructure • Increase power flow from distribution grid equipment; automate distribution substation operations • Provide varying levels of power quality to meet individual customer needs • Integrate DER into distribution grid operations, and enable advanced distribution system operating concepts	• Real-time modeling and simulation for optimal operations and for system planning • Facilitate industry/government collaboration in modeling & simulation

From each Technical Area above, the session participants identified five-to-six top priority activities recommended for 2005-2009; these are summarized in Table 2.

Table 2. High-Priority RD³ Activities Recommended under Each Technical Area

Activity Title	Problems/Needs Addressed
Architecture and Communication Standards	
Define security requirements	Define and implement security requirements in devices or by function classes
Development of a device information model library	Interoperable communication with field devices
Communication & architecture constitution process	Institute an iterative industry-level architecture development
Standards coordination & harmonization	Standards forum and shared website as clearinghouse with DOE facilitation and sponsorship
Entity identity	Common naming and identity management of objects
Monitoring & Load Management Technologies	
Load-management demonstrations	Integration of distributed control from the SCADA/EMS to the lowest level of use
Smart appliances	Inexpensive standardized chip to control appliances load shedding
Next-generation low-cost sensors	Noninvasive sensors for accurate voltage, current, and temperature measurements
Signature library, analytical tools, and signature recognition applications	Correlation of monitored signals and device conditions with system disturbances/events
Integrated monitoring infrastructure and information requirements	Integration of system monitoring with customer-side monitoring technologies
Advanced Distribution Technologies & Operating Concepts	
Enhancing the value of aging infrastructure	Enhancement of existing infrastructure components and practices
Fault locating, prediction and protection	Detect and locate incipient and actual faults on distribution systems
DER integration	Coordination, standardization, and interoperability of multi-DERs
Meeting customer power quality requirements	Enhanced performance and service standards with reactive power control and advanced protection
Advanced operating strategies	Operational optimization to meet increased customer demands for power, power quality, choice, and selectable reliability
Improved infrastructure components	Transition from analog distribution system into digitally controlled system
Modeling & Simulation	
Collaborative Analysis, Design, and Operations for Energy Systems (CADOE)	Collaborative software development environment to leverage/share all resources
Standard data structures to support system analysis and planning	A common tool or translator for seamless data transfer involving distribution and generation/transmission systems
Modeling electric performance metrics along with economic/customer valuation	Tools to optimize distribution operations and planning
Modeling new and existing DER technologies on the distribution system	Operational assessment of DER technologies with the distribution system
Load prediction and modeling tools	Tools to model magnitude, shape, and response of loads as functions of price signals, weather conditions, etc.
Value-based reliability	Understanding of the monetary value that customers place on reliability

Within each Technical Area, the activities in Table 2 are listed in order of decreasing priority. However, due to the overlapping nature of some activities across Technical Areas and other Programmatic considerations such as the overall balance of the Program portfolio of projects with respect to technical risk and economic payback, an overall prioritization of all activities in Table 2 will need to be assessed in view of available funds for investment. This overall prioritization is beyond the scope of the Workshop and will be conducted as part of the OETD's electric distribution R&D planning process for activity implementation, via open solicitation for proposals in select, highest-priority activity areas.

It is recognized that implementing the above list of activities requires significantly greater investments from the private sector than the budgets available in the public sector. Significant investments have already been made and will continue to be made by utilities and communication/information technology communities in upgrading electric distribution infrastructure and infrastructural equipment and components. In electric distribution R&D, OETD will continue its strategy of building public/private partnerships to leverage all available resources to jointly implement the recommended RD^3 activities. The ability of the OETD to launch part of or all of the above activities will continue to rely on advocacy, championship, and financial support from all private-sector stakeholders. This document and its listed activities will be used to help support the OETD's electric distribution budget and to guide its investments in those described activities while leveraging support from the private sector.

It is also recognized that some of the high-priority RD^3 activities, in Table 2, crosscut other government R&D program areas both within the OETD and external of the OETD, including those of Transmission Reliability, Energy Storage, GridWorks, Superconductivity, the DOE Office of Energy Assurance, the Department of Homeland Security, etc. The EDT Program and the GridWise Initiative will seek to collaborate on, coordinate, and leverage RD^3 activities with these applicable programs, wherever possible, and with applicable public/private partnerships such as the Consortium for Electric Infrastructure to Support a Digital Society (CEIDS). Additionally, other public-sector funding such as from the DOE Small Business Innovative Research (SBIR)/Small Business Technology Transfer (STTR) Program, as well as from individual State Energy Programs, will also be leveraged for implementation of the high-priority RD^3 activities listed in Table 2.

Lastly, this document represents a work in progress. The OETD plans to revise and update this document on an annual basis.

1.0 Introduction

The *National Energy Policy* (NEP) Report in May 2001 identified the challenge areas that need to be addressed to attain reliable, affordable, and environmentally sound energy for America's future. In identifying two of these interrelated areas, i.e., "modernize our energy infrastructure" and "increase energy security," the report called attention to the inadequacy and vulnerability of the nation's aging electric infrastructure and the need for its modernization to meet the increasing demand of a modern society. In response to the NEP recommendation, the U.S. Department of Energy (DOE) undertook a comprehensive nationwide study engaging broad participation of stakeholder groups and published its study findings with consensus recommendations in the *National Transmission Grid Study* (NTGS) in May 2002. The NTGS contains 51 recommendations; the culmination of these is DOE's leadership and commitment to create a centralized, new organization, i.e., the Office of Electric Transmission and Distribution (OETD), to reorganize its then-divergent efforts in electricity delivery resources and bring them into focus to commit to implement the NTGS recommendations.

The OETD, established in August 2003, has the mission of leading a national effort to help modernize and expand America's electric delivery system to ensure a more reliable and robust electricity supply, as well as economic and national security. It is structured to perform four primary functions: transmission and distribution (T&D) research and development (R&D), T&D modeling and analysis, electricity import/export authorization, and power marketing liaison.

This document defines technology development pathways recommended for Electric Distribution, as part of the T&D R&D, to address distribution technology research, development, demonstration, and deployment (RD^3) from distribution substations to customer-side load management.

1.1 Electric Distribution

Within the OETD, the Electric Distribution Transformation (EDT) Program and the GridWise Initiative focus their activities primarily on electric distribution R&D. The EDT Program has incorporated all R&D activities previously conducted under the DOE Office of Energy Efficiency and Renewable Energy (EERE) Distribution & Interconnection Program, which focused on integrating distributed energy resources (DER) with electric power systems through development and implementation of interconnection standards, interconnection technologies, and system integration concepts. The GridWise Initiative, a DOE FY05 Initiative, continues activities previously conducted under the EERE Advanced Communications and Controls Program in developing communication and control technologies, based on open and standard protocols, to provide interoperability and scalability of all distribution grid components and subsystems. Additionally, the GridWise R&D will also include development and applications of advanced sensors and information technologies, when combined with advanced communications and controls, to enable modernized electric grid operations where an open but secure infrastructure framework is applied throughout the electric grid to provide value and choices to electricity consumers, also known as GridWise principles of operation. According to *Estimating the Benefits of the GridWise Initiative: Phase I Report (May 2004)*, by Rand Corporation, the gross benefits from GridWise are projected to be in the range of $30 billion to $130 billion over 20 years, depending on various market penetration scenarios, as shown in Figure 1.1.1.

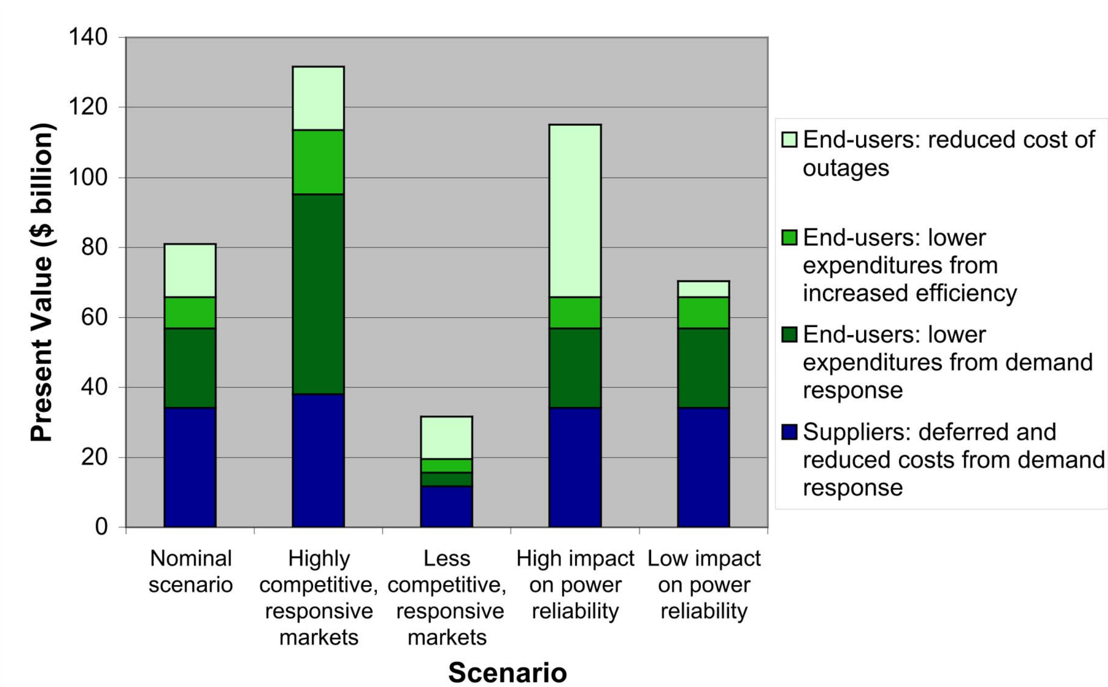

Figure 1.1.1 Supplier and End-User Benefits from GridWise, by Scenario

(Courtesy of The Rand Corporation, as taken from Figure S.1. in *Estimating the Benefits of the GridWise Initiative: Phase I Report,* May 2004)

Thus, through integration of the EDT Program and the GridWise Initiative, as well as other OETD activities, electric distribution R&D is aimed at modernizing the nation's electric distribution infrastructure, employing fast-acting sensors/controls, along with advanced communication and information technologies, throughout the electric grid to enhance reliability and robustness, promote economic efficiencies, and provide value and choices to electricity consumers. This modernization will lead the electric system into the high-tech age to realize the benefits from acquiring and responding to essential real-time information to maximize reliability and system efficiency.

To contribute to modernizing the energy infrastructure and increasing energy security, as outlined in the NEP, electric distribution R&D will transform the nation's aging distribution infrastructure into an intelligent and adaptive infrastructure with integration of advanced sensors, communications and controls, information technologies, and distributed energy resources. The new infrastructure will be designed to be secure from and resilient to natural and man-made failure incidents as well as reliable and responsive to customer needs.

1.2 Development of the Multi-Year RD^3 Technology Roadmap Plan

The OETD undertook its first-ever multi-year RD^3 technology roadmap plan development for electric distribution R&D, aiming to (1) develop a concerted technology plan to support modernization of electric grid operations that will be implemented by both the EDT Program and the GridWise Initiative, and to a lesser extent the GridWorks Initiative, and (2) address the technology needs conveyed in the *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* (April 2004), specifically in the areas of improved capabilities and tools for system monitoring and management and demand response initiatives pertaining to electric distribution operations.

The roadmap development followed a process designed to engage broad stakeholder participation representative of electric utility companies and associations, technology suppliers, electricity users, research organizations (national laboratories and academics), and State/federal agencies. A two-day Workshop was convened on August 17 & 18, 2004, with 83 participants involved in four concurrent Technical Area sessions, at the Exelon corporate facilities in Oak Brook, Illinois. The discussions in each Technical Area session were led and facilitated by two co-chairs, one representing utility stakeholders and the other representing non-utility stakeholders, i.e., either a research organization or a technology supplier or integrator. Before the Workshop, the co-chairs of each session jointly developed talking points, covering the subtopic areas for each session and key information expected to be elicited from participants during the Workshop; this advance material was then sent to all session registrants for their preparation. The Workshop agenda and attendee list are provided in Appendix A & B, respectively, with co-chairs identified in both.

During the Workshop, for each subtopic area, session participants discussed problems, technology gap areas derived from comparison of current vs. desired capabilities, schedules and performance targets, end states once developed, and development strategy. All related technology development was grouped into an RD^3 activity, followed by iterative discussion of all identified RD^3 activities that resulted in a consensus on the top five-to-six high-priority activities from all session participants. For each identified high-priority activity, a champion was then designated from the session participants to be responsible for obtaining more detailed information and planning for this activity (accomplished typically through a subgroup of participants), summarizing and presenting it to all Workshop participants during the wrap-up session, and submitting a detailed summary to the session co-chairs after the Workshop.

Continuing this iterative process after the Workshop, session co-chairs sent the submitted high-priority activity descriptions to session attendees for their input; the session co-chairs then incorporated all input and submitted final activity descriptions to the DOE; these descriptions served as the basis for the content of this document.

The four Technical Areas and the individual descriptions of the five-to-six RD^3 activities identified as top priorities in each Technical Area are presented in Section 2.0.

2.0 Technical Plan

This Technical Plan is intended to provide the detailed information about the RD^3 activities needed to guide implementation of the *National Electric Delivery Technology Roadmap* (January 2004), with a particular focus on addressing the "Distributed Sensors, Intelligence, Smart Controls, and Distributed Energy Resources" critical technology area. The needed RD^3 activities are grouped into four Technical Areas, as presented in the ensuing sections:

- Architecture and communication standards
- Monitoring and load management technologies
- Advanced distribution technologies and operating concepts
- Modeling and simulation

The Technical Plan primarily focuses on the high-priority RD^3 activities recommended to be undertaken in 2005-2009 so that continued, planned progress can be made in these activity areas and ensuing areas to reach the long-term vision described in the *Grid 2030 Vision* (July 2003). Thus, selection of these activities considered time sequencing of technical/technology progression to reach the functionality of "a fully automated power delivery network…ensuring a two-way flow of electricity and information between the power plants and appliances and all points in between."

The RD^3 activities presented in each Technical Area below were selected based on a consensus-building process, and the descriptions below follow the Workshop discussion format of addressing why/what/when aspects for each activity need. During the Workshop, these aspects were illuminated through analyzing, assessing, and discussing the following key elements:

- Problems to be addressed, and end state of each problem once addressed
- Specific technology needs and their performance requirements
- Current science and technology capabilities
- Existing capability gaps (between current and needed states) and barriers
- How activity will fill capability gaps and overcome barriers
- Recommended investment horizon, i.e., near- (1-2 years), mid- (3-5 years), or long- (beyond 5 years) term
- Development strategy and performance targets with associated schedules

2.1 Architecture and Communication Standards

This Technical Area addresses the development of an overall architecture for a "system of systems" to support the transformation of the electrical distribution infrastructure to accomplish the goals of increasing affordability, reliability, security, and resilience. This new architecture needs to define participants, functions, and interdependence relations from a total system perspective, e.g., including all components throughout the generation, transmission, distribution, and customer loads.

Key challenges for the architecture include incorporation of massive installed legacy systems as full participants without degrading performance and reliability, harmonizing multiple industry and standards activities that are not fully coordinated, infusion of available and emerging technologies from other industries (manufacturing automation, process control, etc.), and responses to the distinct issues of normal operation status and emergency operation status (i.e., reacting to day-to-day market events vs. reacting to critical system events). Additionally, security encryption technologies in the architecture must not compromise time-critical functions and timely decision making.

The specific characteristics of the desired architecture are defined to include the following:

- **Transformational** – the style and substance of operation is significantly different from today.
- **Efficiency through economic transparency** – services are offered in a competitive environment to reveal value and provide incentive for efficient operation.
- **Collaborative environment** – system of independent participants transacting business based on mutual agreements with appropriate safeguards for social equity.
- **Distributed participation and control** – push decisions to those areas with the best context and information to act. Facilitate the participation of demand and other distributed energy resources in balancing energy in the system.
- **Evolvable and extensible** – accommodate legacy technical approaches in existing services while stimulating technical innovation to offer new services in a continual process of renewal.
- **Sustainable** – economic as well as technical viability through consistency with mainstream socio-economic and technical trends.
- **Information security and privacy** – effective tools, methods, and policies thwart cyber attacks and support privacy rights.
- **Stable** – enhanced system reliability and resilience to natural or nefarious attack through self-reconfiguration reflecting participants' priorities and preserving overall system health.
- **Safe operation** – respects human health for service providers and users.

2.1.1 High-Priority RD³ Activities

Five major activities were identified in the multi-year RD³ planning workshop to achieve the characteristics of the transformational architecture above. They are summarized in Table 2.1.1; a more detailed description of each activity follows in the ensuing sections.

Table 2.1.1. High-Priority Architecture and Communication Standards RD³

Problems to be Addressed	Technology Needs	RD³ Activities
No well-defined information security requirements or policies; no explicit security requirements for devices, networks, or applicably stated standards	Define security domains (by device, transport, application) and each domain's security portfolio requirements; implement designs with incorporation of full requirements	Define security requirements
To facilitate interoperable communication with field devices and the representation of data associated with them in information systems	Information models with defined attributes and services associated with field devices; tools and standardized language to represent information models	Development of a device information model library
Lack of common vision, requirements, and ongoing dialog and facilitation	Stakeholder engagement to institute an iterative industry-level architecture development	Communication and architecture constitution process
Different groups with different directions and focuses on standards development	Standards forum and shared website as clearinghouse with facilitation and sponsorship by DOE	Standards coordination and harmonization
Different naming and identity management of objects (devices, application functions, etc.)	Establish agreed identity framework within an enterprise, between enterprises, and between industry segments	Entity identity

Other activities with second-tier priorities to those listed in Table 2.1.1 include the following:

- Tools to model and simulate system design: both power system and communication system
- Spectrum management/allocation for utility wireless communication
- Testing of complex system designs, including the need for SCADA security assessment tools
- Complete set of architecture-defining scenarios (use-cases) to drive requirements. Consider both market evolution issues and future power systems advanced automation issues.

2.1.1.1. Define Security Requirements (authentication, integrity, privacy, key management, symmetric vs. asymmetric) in Terms of Device or Function Classes

Problems to be addressed, and end state of each problem once addressed

Enterprise commercial success depends, among other traits, on safeguarding information systems from intrusion, external and internal information tampering, and disaster recovery.

Enterprise security strength evolved over time as a direct result of increased security defect awareness and continuous security product provisioning. To remain in business, security investments were required that resulted in new product solutions and strengthened enterprise positions.

Over the past 20 years, investments in the electrical energy grid have not kept pace with commercial enterprise. Electric energy systems have been built over many years, leaving in place significant legacy systems. These legacy systems are, for the most part, incompatible with modern information systems; thus, they are incompatible with modern information security systems. Today, most investments in utility security focus on physical security. Investments in information security are, at best, reactionary to breaches.

In the electric energy industry, there are no well-defined information security requirements or policies. There are no explicit security requirements for devices, networks, or applicably stated standards.

Specific technology needs and their performance requirements

Security strengthening must be tempered against business risk and associated costs. Therefore, the proper level of security must be specified according to the level of risk and defined by security domain.

Currently, general lack of definition of a security portfolio (e.g., system hardening, residual risk) must be resolved in such a way to create compatibility between vendor solutions and interagency (utility, DER, ISO, RTO, etc.) solutions. Specific problems that need to be addressed include:

- Define consistent implementation approaches to security policies (reference NERC work)
- Maintain interoperability of all components and systems (including legacy, real-time, physical, and environmental)
- Modernize, through evolution, the electrical distribution system through these standards and policies
- Define a security domain classification for communication and architecture (i.e., devices, network, transport, messaging, languages, server, application)
- Define security requirements within each domain, including authentication, integrity, privacy, key management, symmetric vs. asymmetric, performance, language, and scalability
- Define standards to satisfy each domain requirement
- Map security requirements to existing security certification levels (e.g., FIPS)
- Promulgate Intelligrid environment domain maps

- Identify specific requirements for wireless networks
- Harmonize security and application requirements to achieve application performance requirements
- Create security assessment tools

Current science and technology capabilities

As new security technologies emerge, new means to compromise them follow. Enterprises invest heavily to maintain the proper balance of security defenses against business risk. Technologies include various intrusion detection, encryption, key management, “firewall technologies,” transport-level security, and secure management functions (i.e., SNMP v3).

At present, numerous guidelines and potential standards are being discussed and promulgated regarding the securing of communications associated with electric power system control and protection systems and equipment to mitigate unauthorized access. These include dedicated networks, interconnection with general business networks only through firewalls or similar technology, encryption, and intrusion detection systems.

Existing capability gaps (between current and needed states) and barriers

In spite of general industry security solutions, specific requirements to meet DHS and critical infrastructure are inadequately specified. Manufacturers try to meet requirements, but must satisfy a majority of their customers’ product requirements. Without industry-wide requirements, each electric energy solution provider selects products meeting their own risk assessment requirements. Across the industry, individual security portfolios are inconsistent, leading to inadequate, non-uniform vendor implementation.

The following gaps are identified:

- Current policies and standards bodies do not provide security guidance by domain (device, transport, application)
- Standards leading to open systems policy provisioning (this has not occurred)
- Means to consistently and uniformly integrate systems or security functions
- Security specifications for real-time vs. asynchronous
- Security specifications for wireless communications
- Electric energy security modeling tools

How activity will fill capability gaps and overcome barriers

A consistent implementation approach will lead to product and business function interoperability. This in turns leads to product availability, competition, and ultimately market influences that lower costs while maintaining compliance to stricter security requirements.

By standardizing within each domain, architectures will be easier to model, build, monitor, and scale out. Product choices will increase. Incorporating solutions to transforming legacy systems will avoid write-offs and lead to continued profitability. This will encourage further investments in similar technologies.

Standards and policies will lead to a well-documented security portfolio for enterprise. This leads to consistency and easy maintenance. Business risk will lower as a direct result of increased security. Lower risk leads to better profitability.

Security assessment tools will lead to regular monitoring, technology refresh, risk assessment, and resiliency/responsiveness to unforeseen security events.

Recommended investment horizon and performance targets

A staged investment plan will provide solutions meeting industry needs. In the near term (1-2 years), investment events include:

- Defining security domains
- Define requirements and policies within each domain
- Define each domain's security portfolio (applicable standards and design requirements)
- Specify designs to fulfill requirements

Mid-term (3-4 years) investment events include:

- Creation of security modeling tools
- Pilot implementations of designs for industry

Development strategy

The following steps are recommended to fulfill this objective:

- Assemble working group
- Create security domain classification for communications and architecture
- Create entire security portfolio requirements for each domain
- Leverage existing standards development to specify requirements for each domain
- Identify gaps between requirements and existing standards
- Supplement existing standards work with new effort as revealed in gap analysis
- Focus on urgent needs, e.g., the California demand-response initiative; CEIDS programs should be leveraged to drive standards and policy definition

2.1.1.2. Development of a Device Information Model Library

Problems to be addressed, and end state of each problem once addressed

To facilitate interoperable communication with field devices and the representation of data associated with them in information systems, a consistent set of device information models is required. The end state is achieved by having a library of information models that the industry agrees on and can use in a variety of contexts that is independent of implementation technologies.

Specific technology needs and their performance requirements

An information model needs to identify and name the key attributes that are associated with the device. This includes information that must be set into the device (e.g., configuration, control inputs) or read from the device (e.g., measurements, status information). It also includes a description of services offered by the device such as file transfer, select before operate, attribute discovery, etc. Tools and standardized language to represent these information models are also required.

Current science and technology capabilities

The IEC 61850 and 61970 standards have defined information models for a significant number of power systems devices. Protective relays are particularly well modeled in 61850. Activities are underway in other IEEE and IEC TC 57 venues to model DER devices, power quality meters, wind turbines, and hydroelectric facilities. These models are largely independent of the protocols used to implement them and can be used as a starting point for the development of a comprehensive model library. Presently these information models are represented as tables in Word documents. Some work has begun on developing an XML representation. UML representation has been used for the 61970 CIM effort.

Existing capability gaps (between current and needed states) and barriers

Although information models exist for some devices, many more have not been modeled by a standards organization. Some devices, however, have been modeled in multiple forums and need to be harmonized. A standardized method (language) for representing information models must be developed or selected. No tools (other than generic XML modeling tools) are currently in widespread use to manipulate these models.

How activity will fill capability gaps and overcome barriers

An information model library will be immediately useful to implementers of object oriented information systems and eliminate the need to "roll their own." A modeling language and tools, and guidelines for using them, will facilitate quicker adoption and implementation of the information models in new systems.

Recommended investment horizon and performance targets

Information models are needed now (1-2 years) to facilitate early implementation of object oriented communication protocols. High degrees of parallelism can be achieved to create such models quickly. Tool selection/development could occur within a similar time frame.

Development strategy

Identify and prioritize power system equipment without information models, find domain experts that understand the information that needs to be exposed, document the information models in a standardized format, hold workshops to discuss and refine the models, and initiate field demonstration projects to validate the usability of the models. This work should be closely coordinated with the relevant IEEE and IEC development activities. As an example, the CEIDS DER object model development effort has followed this model, has been very successful, and is closely coordinated with IEC and IEEE standards activities.

Review tools and methods for representing information models, and develop guidelines for their use to represent, manipulate, and maintain the information model library.

2.1.1.3. Communication and Architecture Constitution Process

Problems to be addressed, and end state of each problem once addressed

- Helps establish buy-in
- Develops a common vision
- Establishes governance rules and change management (Amendments)

Specific technology needs and their performance requirements

- Technology agnostic, requirements driven
- Allows technology diversification and evolution
- DOE must coordinate this effort with other relevant government agencies

Current science and technology capabilities

Many efforts are trying to look at this (e.g., GridWise, IECSA, others?), but they are not fully coordinated yet.

Existing capability gaps (between current and needed states) and barriers

- There currently does not exist an architecture that allows the energy stakeholders to effectively manage the grid
- Current grid stops at the meter…this will help us manage the total energy infrastructure

How activity will fill capability gaps and overcome barriers

- This effort overcomes the lack of common vision, requirements, and ongoing dialog and facilitation
- Overcomes IP barriers by providing a common framework for system architecture design

Recommended investment horizon and performance targets

- 1-2 years: stakeholder engagement plan—meeting, communications, travel, presentation; get the word out
  - Constitution strawman to stakeholders in 6 months
  - Further input and revisions over the next year
- 3-5 years: final ratification and the twice yearly stakeholder and governance meeting for change management
  - Final ratification in year-3

2.1.1.4 Improved Standards Coordination and Harmonization

Problems to be addressed

Today, work is under way with a number of standards that will impact distribution systems. These include standards for communications in substations, on distribution feeders, to distributed generation, and for meter reading. Most of these standards are being developed as separate entities with little coordination between them. Any coordination that does exist is due to the fact that many of the same people serve on the different standards committees. The main issues are:

- Lack of coordination between standards development organizations developing standards in the field
- Lack of harmonization in development and with existing standards
- Slow development of standards in emerging technology areas
- No validation of requirements written into standards

Current State

Today, standards work and object models are being developed by many different groups. There is no "big picture" of what needs to be done so that when the standards are complete they will all work together.

- Present standard developed at "parts" level
- Many groups, i.e., CEIDS, EPRI, DOE, IEEE, IEC, Users groups, etc.

Gaps/Barriers

Because of the work being done by many different groups, there is sometimes a lack of knowledge of what is being done by others. This lack of knowledge leads to delays and potential duplication of work between the various groups. The gap that needs to be addressed is the lack of coordination between groups working on standards.

- Different groups with varying directions/focus
- Lack of recognition of existing standards
- Potential duplication of work

How to fill gaps

This gap can be filled by disseminating information from all groups working in this area to facilitate discussions and interchanges of ideas. This process will help build consensus and speed the standards process. Ideas must be brought forward to increase utility involvement in this process, since in most cases it is utilities that need to implement the standards.

Recommended actions

Three actions are recommended to be implemented by DOE:

- Facilitate the coordination between the standards organizations
  - Create a shared website where standards information could be shared
  - Sponsor a standards forum where people involved in standards work could come together and discuss coordination of work
  - Sponsor participation of User groups in standards work (UCA International, DNP, etc.)
  - Sponsor web conferences on a regular basis where various standards groups could coordinate their work
- Fund validation work for the standards that are under development
  - A “test drive” of the standard before it is final would help spot areas that are inadequate and get them corrected
- Fund utility participation in standards groups
  - Many utilities will not send representatives because there are insufficient funds and manpower to actively participate

Recommended investment horizon and performance targets

The work in this area will be spread over near, mid, and long term, as follows:

- 1-2 years
  - Convene a standards forum that brings together parties that write industry consensus standards and that also know how to develop and harmonize standards in a professional manner (i.e., IEEE, ANSI, etc.)

    - Create website with standards information about distribution systems
    - Identify gaps that exist in present standards
    - Fund utility participation in standards organizations
- 3-5 years
    - Test drive emerging standards
    - Assess progress towards final standards
    - Define improvements to the existing standards
- 5+ years
    - Facilitate standards revisions and updates

2.1.1.5. Entity Identity

Problems to be addressed, and end state of each problem once addressed

- Different users of entity identification (human and machine)
- Must support different names for same thing by different users
- Lack of uniqueness to absolutely identify an entity across systems and organizations
- Legacy identity schemes must be handled
- Identifier creation mechanism needs recognition, responsibility, and authority

Specific technology needs and their performance requirements

- Problem not unique to power industry, but exacerbated by scope of interoperability (blurs w/ building, industrial, residential, asset management, financial systems, etc.)
- Mainstream approaches (borrow from best practices emerging from other industries)
- Needs consistency with international approaches

Current science and technology capabilities

- Not green-fields research, but requires investigation of existing and emerging identity frameworks; for example, this type of problem has been tackled worldwide in regard to Internet interoperability
- Other areas of power industry grappling with this problem (operations, planning, energy transactions), but no overarching approach

Existing capability gaps (between current and needed states) and barriers

- Non-agreed-upon identity framework
    a. Within an enterprise
    b. Between enterprises (B2B)
    c. Between industry segments
- Must support “local” identity scheme simultaneously

How activity will fill capability gaps and overcome barriers

- Can borrow from analogous work in other industries
- Emerging general IT approaches can be applied – needs investigation

Recommended investment horizon and performance targets

Must be accomplished in the overall context of the architectural framework.

- Near to mid-term: conceptual framework (research/requirements/proposal)
  - Investigation of approaches – 2005
  - Preliminary proposal – 2006
- Mid to long-term: adoption
  - Roll-out strategy and initial adoption – 2007/2008

2.1.2 Timeline and Key Performance Targets

Key performance targets with associated schedules for each high-priority architecture and communication standards RD^3 activity are depicted in Figure 2.1.2.1.

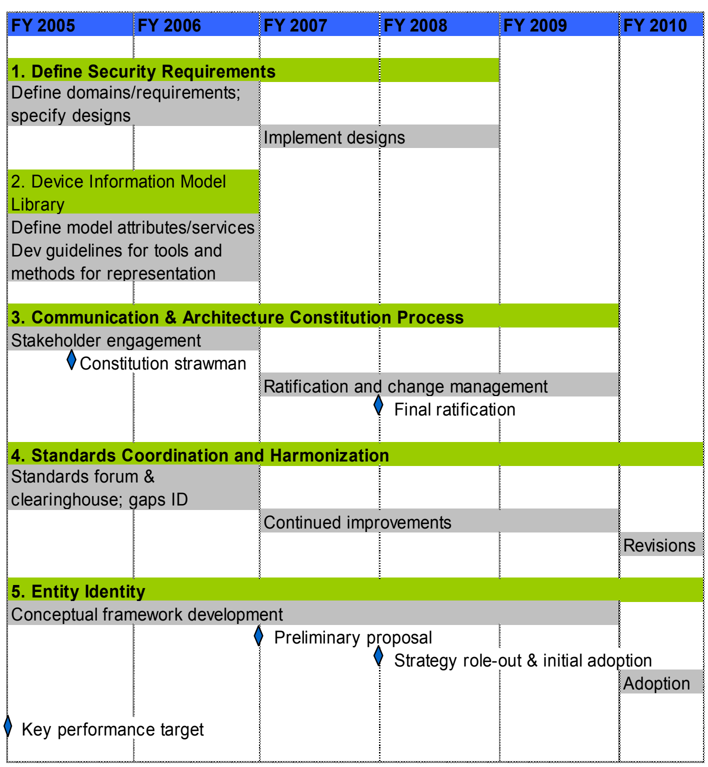

Figure 2.1.2.1 Performance Targets for Architecture and Communication Standards RD^3

2.2 Monitoring and Load Management Technologies

This Technical Area focuses on technologies (1) to monitor distribution circuit for power quality and (incipient) fault locating/prediction/prevention (description of fault locating/prediction/prevention covered under Section 2.3.1.2), and (2) to monitor and control industrial/commercial/residential loads to participate in demand-side management (DSM) programs. The end state that this Technical Area will enable is to provide highly reliable distribution grid operations through timely fault detection and response, as well as to provide customer choice and affordability in electricity consumption through participation in and management of loads based on market pricing signals. Thus, this technical area supports distributed sensing, monitoring, and control, with provision of transparency of market and pricing operations, of all levels of customer loads, down to the level of household appliances.

2.2.1 High-Priority RD^3 Activities

Five major activities were identified in the multi-year RD^3 planning workshop. They are summarized in Table 2.2.1; a more detailed description of each activity follows in the ensuing sections.

Table 2.2.1. High-Priority Monitoring and Load Management Technologies

Problems to be Addressed	Technology Needs	RD^3 Activities
Customers' ability to respond to real-time and day-ahead market signals; business cases and customer value in participating in DSM programs	Integration of distributed control from the SCADA/EMS and to the lowest level of use, i.e., appliances; two-way communications with adequate bandwidths and speeds	Load-management demonstrations
Load shedding control during under-voltage or under-frequency events to improve system reliability	Inexpensive standardized chip to set optimal off/on operations of appliances and for intelligent restoration schemes with random turn-on delays during disturbance events	Smart appliances
Utility operators do not know the load, voltage, and temperature of cables	Small, inexpensive, durable, self-powered, and noninvasive sensors for accurate voltage, current, and temperature measurements	Next-generation low-cost sensors
Correlation between monitored signals and associated device conditions, system disturbances, system events, etc.	Coordinated database development to collect data from actual events from many systems for signature recognition analysis to support diagnostic and condition assessment applications	Signature library, analytical tools, and signature recognition applications
Integrated monitoring infrastructure to integrate system monitoring with customer-side monitoring technologies and to provide interface protocols and data formats for other information systems and analysis applications	Integration of monitoring systems for different applications (e.g., power quality, power flow management, equipment diagnostics, fault locating/protection, etc.) and other information systems (e.g., GIS, electrical models, operations, customer systems) to maximize value	Integrated monitoring infrastructure and information requirements

2.2.1.1. Demonstrations of Load-Management Technologies and Practices

Specific technology demonstrations are needed to support both the ability of the utility to monitor/control its system and the ability of the customer to respond to real-time and day-ahead market signals. A sound business case and value proposition to participants should precede any demonstrations, and examining and "tweaking" the business case should be the central focus of the demonstration.

Problems to be addressed, and end state of each problem once addressed

The problem this activity is intended to address is how to improve overall utilization of the grid, i.e., driving to a 75 percent or better load factor and achieving maximum efficiencies of the present grid. This involves demonstrations of technologies that bring control all the way from the highest to the lowest end-use levels. The technologies for demonstrations are deemed available now, but require integration and simplification; demonstrations are needed to achieve utilization in the market.

Greenfield New Home Demonstration

This demonstration involves working with a builder in a new subdivision, of at least 200-300 homes, a new school, or a strip mall, to deploy not just Energy Star maximum efficiency appliances, but also appliances that have GridWise capabilities to enable them to automatically respond to system prices and conditions. Other technologies for this demonstration may include combined heat and power generation to capture waste heat to provide space heating and energy storage devices, like in the new hybrid vehicles, to allow on-site energy storage to improve power quality and power factor. One scenario for incorporation of energy storage is to equip each community, on an aggregated basis, with a band of batteries that provides 25 percent of demand at certain times of high market prices and/or system congestion. The appliances deployed should have transparent load control and signaling of service needs, similar to a vehicle signaling its owner that the engine needs maintenance from dashboard light prompts.

This demonstration will support the business case by examining the actual payback period of using enhanced, efficient, and demand-response appliances, which could then serve as a marketing tool for these appliances to the new home builder market.

Retrofit Demonstration

This demonstration is to be conducted in a low-income, high-density community in which major appliances are owned, and electricity bills are paid, by the building owner. Similar types of appliances as described above, perhaps with government assistance, are to be deployed. Use of an existing community with good energy use baseline data would strengthen impact analysis. Because low-income communities can often be found in inner urban areas with transmission congestion, the system value of installation of efficient demand-responding appliances could also be evaluated. Actual load reduction would be verified with monitoring schemes for two-way communication, and the amount of demand response penetration necessary to alleviate price spikes or other undesirable system conditions could be evaluated.

In support of the business case, measuring the payback period of deployment of enhanced, efficient and demand-responsive appliances could demonstrate the value of such appliances to building owners, who would lower their operating costs through such deployments. Studying the building occupants' reactions to the demand response features of their new appliances would yield market data that would be important to manufacturers in rolling out such appliances to the mass market.

Congestion Relief

Another important demonstration is to show the value of demand response and distributed generation in congested substations/feeders, the value of VAR control, enhanced reliability, etc. The value of demand response and distributed generation is not simply in the savings and/or prices that each decrement of energy might be worth in terms of its generation component, but also in its transmission and distribution components, which are currently largely unacknowledged. Incorporating T&D congestion-relief values into the equation of how much DER is worth may make apparent its value not only to the participant but also to society, which would be of interest to regulators.

Specific technology needs and their performance requirements

These demonstrations would involve placing chips in appliances, and manufacturing "smart" appliances that can respond to market signals. These chips are currently available, and manufacturers are beginning to evaluate their capabilities and marketability in home usage. The demonstrations would also involve two-way communication. Different communication paths are being explored, possibly moving towards broadband communication, web-based infrastructure. Work needs to be done to achieve enough uniformity of signalization that system-level resources could recognize the appliances and communicate with them.

Current science and technology capabilities

Most of the technologies proposed here are now available but are not incorporated in appliances or SCADA/EMS systems.

Existing capability gaps (between current and needed states) and barriers

SCADA and other grid-recognition systems are presently configured to recognize and control typical utility assets, not demand-side assets. New communication and interconnection business models need to be explored. System characteristics of specific locations where DER participation has maximum value need to be developed so that these locations can be targeted and possibly incentivized. The vendor community needs open recognition standards and protocols for manufacturers, and DOE leadership needs to require these standards to be incorporated in end-use appliances. The aggregator needs new products such as contracts and tariffs that incorporate sharing of the values to be derived from end-user responses to market signals.

How activity will fill capability gaps and overcome barriers

The suggested demonstrations will show values of the technologies deployed by bringing customer loads to participate in markets under voluntary conditions, therefore moving the paradigm well beyond the traditional practice of load management that has for the last 25 years been primarily deployed as emergency and interruptible programs. The demand response demonstrations herein described will be economic, customer-driven, and voluntary, and will drive down the cost of smart chips and electricity. If they can be deployed in distribution areas where transmission is constrained, they may also delay construction of new transmission for significant cost savings to consumers.

Recommended investment horizon and performance targets

As most technologies are currently available, the horizon would be from 1 to 5 years:

- By end of 2005, have Greenfield or low-income community selected
- By 2006-2007, have Greenfield built or low-income community demonstration completed
- By 2008, have results and mass marketing campaign launch

2.2.1.2. Smart Appliances

Problem to be addressed, and end state of each problem once addressed

Large-scale system disturbances can black out large sections of the country; with under frequency sensing and load drop control on appliances, major outages could be avoided.

Specific technology needs and their performance requirements

An inexpensive standardized chip that will drop off appliance loads during reliability events, based on under frequency setting, is needed. Also, the chip should be capable of providing:

- Intelligent restorations (random turn-on delay)
- Optimal off/on duty cycles by appliance

Also needed are two-way communications (in-house/in-building PLC, IP-based access to site such as cables, DSL, wireless, etc.).

Current science and technology capabilities

- Chip exists in prototype (Grid Friendly Appliance controllers at PNNL); price point is too high currently
- Have pieces of scheme, but lack integration into specific appliances

- Have load control processor in a few demand response systems, but not widely used nor is value to system recognized
- Too much customization in commercial settings; need templates by business types

Existing capability gaps (between current and needed states) and barriers

- No business model to scale in either residential or commercial sectors
- No widespread communication capabilities, broadband not in every building
- No embedded load control intelligence demand from manufacturers or consumers, thus no devices in current appliances

How activity will fill capability gaps and overcome barriers

- Will demonstrate the practicality and economic path for implementation
- Verify test response via 2-way communications (broadband and PLC in home and business sites) for real-time monitoring
- Determine optimal off/on time frames by appliance type

Recommended investment horizon and performance targets

Test the Grid Friendly Appliance controller in a wall bug form (2-outlet device) and/or in line for hot water heater (best test) in both home and business.

- 1-2 years: demonstrate wall bug under-frequency and under-voltage devices with 2-way communications for measurement and verification
- 3-5 years: assuming the concept works, make the smart appliance chip become the heart of "Energy Star+"
- 5 years & beyond: commercialization and market transformation with rebates and/or incentives to consumers and manufacturers

2.2.1.3. Next-Generation Low-Cost Sensors

Problems to be addressed, and end state of each problem once addressed

Utility operators do not know the load, voltage, and temperature of cables. This information is needed for state estimation, informed control, and remaining life estimation, as well as to validate models and simulations and to discover outliers.

Specific technology needs and their performance requirements

- Small, cheap, noninvasive (outside insulation or on bare conductor)
- Durable, easy to apply, accurate voltage, current, and temperature sensor(s) with interface to advanced communication (develop separately)
- Self-powered (parasitic)

Current science and technology capabilities

- Small temperature and current monitors
- Recent developments in radio-frequency identification (RFID) form factor, size, and cost may be a route to success

Existing capability gaps (between current and needed states) and barriers

- Gaps
  - Accurate voltage
  - Easy to apply
  - Durable/hardened
  - Communication interface
- Barriers
  - Communication
  - State estimation
  - Remaining life estimation

How activity will fill capability gaps and overcome barriers

This project will develop sensors and their form factors capable of monitoring steady-state current, voltage, and temperature at a sampling rate of five minutes or less and that are durable, easy to apply, and self-powered (parasitic) for both low-voltage and medium-voltage cables.

Recommended investment horizon and performance targets

- 2005-2006: engage two vendors to complete development and testing, in laboratory/field, of the "sensor straps" or "sensor motes"
- 2007-2009: select optimal device and produce 5,000 units integrated with appropriate communication modules (develop separately) and install them in several real-world test beds (primary and secondary, in underground network, underground residential distribution, and overhead systems); Optimize form factor and production techniques to achieve price point of $1 to $5 per unit by 2009

2.2.1.4. Signature Library, Analytical Tools, and Signature Recognition Applications (Knowledge Base)

Problems to be addressed, and end state of each problem once addressed

- Lack of correlation between monitored signals and associated device conditions, system disturbances, system events, etc.
- Lack of common structure for saving monitored information in a form that can be used for analysis application development

- Lack of software for managing and processing the data for intelligent applications
- Need for diagnostic and condition assessment applications

Specific technology needs and their performance requirements

- Standard method and specification for saving monitored information along with system conditions (electrical, status, timing, monitored data) for use in application development
- Actual database of events with correlated system conditions large enough to support application development
- New approaches for processing of monitored data to identify system conditions, equipment conditions, etc.

Current science and technology capabilities

- Monitoring databases without correlation to actual system events associated with the monitoring data
- Monitoring data without electrical and other information to support analysis of the events
- Some intelligent applications that are tested primarily with simulation data and may or may not be applicable to real data

Existing capability gaps (between current and needed states) and barriers

- Gaps
  - Lack of data with correlated system and equipment conditions
  - Lack of common database structures for managing the monitoring information for intelligent applications
  - Lack of tools for extracting critical information for decision making
- Barriers
  - Labor and effort required to document conditions associated with monitored events
  - Existing data structures, proprietary systems (legacy systems)
  - Limited tools for data management and processing

How activity will fill capability gaps and overcome barriers

- A framework for the database of electrical disturbances and monitored data with correlated electrical and system event information will be developed with participation of interested parties to assure that legacy systems can be integrated
- Coordinated data collection from many systems to populate the database with events—each participant would not have to invest a large amount in the data collection effort if a large number of participants can be recruited

- Data analysis to identify signatures and characteristics that can be used for intelligent applications and diagnostics
- Demonstrations to illustrate value of applications that can be developed once data and information are available

Recommended investment horizon and performance targets

- 2005-2006: framework development; publication of framework and library for widespread application development in 2006
- 2005-2007: coordinate data collection from many different systems using the framework
- 2006-2009: data analysis to identify important characteristics
- 2006-2010: development of intelligent applications and demonstrations of their application and performance in the field

2.2.1.5. Develop Infrastructure and Requirements for Integration of Monitoring Information

Problems to be addressed, and end state of each problem once addressed

- Many different devices can contribute to the overall system monitoring requirements, but no standards exist for integrating these devices. This project will define the integration infrastructure and requirements.
- Monitoring infrastructure needs to take advantage of customer-level monitoring (e.g., meters) as well as system monitoring—information models are required for the customer interface. This project will define the requirements for integration of smart meters and other customer-side monitoring technologies.
- Common object models are needed to define the information requirements as a function of the monitoring application (e.g., power quality, power flow management, equipment diagnostics, fault location, protection, etc.). This project will define and demonstrate these object models for implementation in any intelligent electronic device (IED).
- Monitoring systems need to be integrated with other information systems (e.g., geographic information system [GIS], electrical models, operations, customer systems) to maximize value. The integration infrastructure specification will define this structure.
- The ability to maximize information from limited locations (take advantage of interface with other information sources to extrapolate information, e.g., state estimation) is needed. The integration structure will allow for estimation of information as well as actual measurement.
- A convenient interface for analysis applications and development of applications to maximize value of the information are needed. Requirements for interfacing to the monitoring information for general applications will be defined.

- The result of expanded monitoring will be a large amount of monitoring information that needs to be managed with critical information extracted for decision making. The project will define a hierarchy for monitoring information management that can facilitate distributed processing and transfer of information efficiently between applications.

Specific technology needs and their performance requirements

- Overall monitoring system information model for different applications
    - Specific monitoring information required vs. application
    - Volts, vars, phase angles for general power flow and system optimization
    - Power quality characteristics for benchmarking, regulations, contracts, and customer services
    - Disturbance waveforms and other characteristics for fault location, fault analysis, switching conditions, equipment diagnostics, etc.
    - Other information (temperature, environment) for diagnostics
- Trended data (wide variety) for historical and stochastic assessments
- Interfaces to other information systems vs. application
    - Interface to distribution management systems for outage notification, fault location, etc.
    - Interface to electrical system models for state estimation, planning, etc.
    - Interface to customer information systems for customer impact evaluations and interfaces to demand response applications
- Specification for interface protocols and data formats for different applications in order for existing equipment to be integrated with an overall monitoring system:
    - Relays
    - Reclosers
    - Controllers (e.g., capacitor controllers)
    - Meters
    - Industrial and commercial monitoring systems
- Overall data management functions
    - Data collection (communication infrastructure definition)
    - Database structures
    - Data management algorithms to handle large amount of information and identify critical information
- Analysis functions
- Reporting and visualization functions

Current science and technology capabilities

- Monitoring systems for different applications that are not integrated
    - Monitors available with data capture capability, but not integrated in an overall system

    - High-end monitors available for advanced monitoring applications, but not part of monitoring system
- Database structures for different applications
    - Power quality only
    - SCADA
    - Customer systems
    - Automatic meter reading (AMR)
- Variety of independent communication systems for specific applications (high cost and often limited bandwidth)

Existing capability gaps (between current and needed states) and barriers

- Gaps
    - Integration of information—protocols, information models, information management
    - Integration of different information systems
    - Data management to extract critical information for decision making
- Barriers
    - Proprietary systems
    - Standards development difficulties
    - Communication system implementation
    - Legacy systems

How activity will fill capability gaps and overcome barriers

- Project will engage wide range of interested parties for standards and object models development to facilitate integration
- Technical development required for data management, information extraction, and integration requirements
- Demonstrations to illustrate feasibility of integration
- Economic assessments to demonstrate benefits of integration

Recommended investment horizon and performance targets

- 2005: characterization of existing systems and devices to be integrated
- 2005-2006: standards development, object model development, consortium approach—form an open-source community to develop, maintain, and upgrade the source code that can benefit all the utilities and product vendors (take the standard to the next level)
- 2006-2009: demonstrations and advancements of new database structures, with integration of devices and application development (intelligent applications, diagnostics, fault location, etc.)
    - Test with existing systems (prototypes) - 2006

- Integration of monitoring technologies
  - Substation equipment - 2006
  - Feeder equipment - 2007
  - Customer site monitors and meters - 2008

2.2.2 Timeline and Key Performance Targets

Key performance targets with associated schedules for each high-priority monitoring and load management RD^3 activity are depicted in Figure 2.2.2.1.

Figure 2.2.2.1 Performance Targets for Monitoring and Load Management RD^3

2.3 Advanced Distribution Technologies and Operating Concepts

Local distribution systems will need to evolve substantially to meet the requirements of the *Grid 2030 Vision*. The biggest challenge for the distribution system today is aging infrastructure and finding cost-effective ways to integrate new technologies into the nation's legacy systems. Reliability will need to become more customized so that customers will be able to choose the level that best suits their individual needs. Asset utilization will increase so that 75% of distribution capacity is employed on average.

This Technical Area will address advanced technologies to diagnose conditions of the existing/aging distribution infrastructure, to increase power flow from distribution grid equipment, to automate distribution substation operations, to provide varying levels of power quality to meet individual customer needs, to integrate DER into distribution grid operations, and to enable advanced distribution system operating concepts, such as microgrids, intentional islanding, etc. With respect to DER integration, this Technical Area will continue to support development of advanced modular plug-and-play technologies for interconnection with the electric power system, as well as to support establishment of the IEEE 1547 series of interconnection standards and development of international standards via the International Electrotechnical Commission (IEC) Technical Committee 8 (TC 8), System Aspects of Electrical Energy Supply.

2.3.1 High-Priority RD^3 Activities

Six major activities were identified in the multi-year RD^3 planning workshop. They are summarized in Table 2.3.1; a more detailed description of each activity follows in the ensuing sections.

Improved electric distribution equipment/components, specifically on cables and conductors, power electronics, and substation equipment, described in this section are also the subject of a separate workshop sponsored by the OETD for the GridWorks Initiative on October 20-21 in Chicago, Illinois. The activities and discussions brought forth by participants of both Workshops are complementary; the recommendations from both Workshops will be considered to guide OETD investments in electric distribution equipment and components.

Table 2.3.1. High-Priority Advanced Distribution Technologies and Operating Concepts

Problems to be Addressed	Technology Needs	RD^3 Activities
Aging of distribution infrastructure components (cables, wood poles, substation transformers, circuit breakers), workforce effectiveness, and vegetation management	Enhanced reliability, capacity, durability, and maintainability of existing infrastructure components; improved workforce effectiveness, and effective vegetation management practices	Enhancing the value of aging infrastructure
Systems or tools to detect and locate incipient and actual faults on distribution systems	An integrated system equipped with a sensor to monitor current and voltage coupled to an intelligent electronic device that in turn operates a sectionalizing device; also capable of interacting with outage management systems	Fault locating, prediction and protection
Coordination, standardization, and interoperability of, and interactions among, multiple DERs	Standardized and low-cost interconnect interface equipment, advanced control algorithms for multiple DERs, and methodology for determining maximum DER penetration	DER integration
Utility delivery services have not evolved to meet new customer loads and needs—unmet customer expectations	Enhanced performance and service standards with dynamic reactive power control and advanced self-healing protection capabilities	Meeting customer power quality requirements
Alignment of utility distribution system operational optimization to meet increased customer demands for power, power quality, choice, and selectable reliability	Integration of ubiquitous inexpensive telecommunications, information systems, and power electronic conversion technologies into distribution system operations	Advanced operating strategies
Transition from analog distribution system into digitally controlled system	New system configuration concepts with more widespread use of IEDs, distributed communication and control, solid-state power electronic devices, and open communication architecture standards	Improved infrastructure components

2.3.1.1. Enhancing the Value of Aging Infrastructure

This RD^3 activity deals with equipment associated with the aging infrastructure (specifically, underground cables, wood poles, transformers, and circuit breakers), workforce effectiveness, and right-of-way vegetation management.

Problems to be addressed, and end state of each problem once addressed

- Underground Cable Reliability – By 2009
    - Reduce cable failure rates by 50%
    - 70% accuracy of failure prediction of mainline cable
- Underground Cable Affordability – By 2009
    - Reduce replacement cost by 25%

- Wood Pole Reliability – By 2009
  - 90% accuracy of remaining life prediction
- Distribution Substation Transformer Asset Utilization – By 2009
  - Increase effective capacity by 15%
  - Reduce failures by 50%
- Distribution Circuit Breaker Reliability – By 2009
  - Reduce improper operations by 50%
- Workforce Effectiveness – By 2009
  - Eliminate human-error-caused distribution outages
- Right of Way Affordability – By 2009
  - Reduce the cost of distribution vegetation management by 10%
- Right of Way Reliability – By 2009
  - Reduce vegetation management related distribution outages by 20%

Specific technology needs and their performance requirements

- Underground Cable
  - Improved cable diagnostics technologies
  - Improved cable life extension technologies
  - Improved directional cable boring technologies
- Wood Poles
  - Improved pole diagnostics tools
- Distribution Substation Transformers
  - Develop test bed for evaluating technologies for increased capacity
  - Evaluate increased capacity technologies
  - Evaluate diagnostics technologies
- Distribution Circuit Breakers
  - Evaluate and demonstrate improved diagnostics technologies
- Workforce Effectiveness
  - Improved training and simulation tools
  - Better tools for reduced human error
- Right of Way
  - Develop tools and methods to reduce vegetation-management-caused outages

Current science and technology capabilities

- Underground Cable
  - Existing diagnostic tools have limited capabilities and are expensive to use
  - Directional cable boring is effective, but costly
- Wood Poles
  - Existing tools are difficult to use, inaccurate, or costly

- Distribution Substation Transformers
  - Existing capacity improvement technologies are unproven with limited field testing and experience
- Distribution Circuit Breakers
  - Need integration of numerous diagnostic tools to create affordable diagnostic package
- Workforce Effectiveness
  - Loss of worker experience, knowledge, and lack of effective training tools to build competencies quickly
- Right of Way
  - Better tools and systems to determine when vegetation management is needed
  - Better understanding of reliability associated with vegetation-caused interruptions

Existing capability gaps (between current and needed states) and barriers

- Underground Cable
  - Lack of knowledge, technical understanding, and investment to improve cable diagnostics technologies
  - Lack of investment to improve trenchless cable equipment
- Wood Poles
  - Lack of knowledge, technical understanding, and investment to wood pole diagnostics technologies
  - Lack of competition to drive development of diagnostic tools
- Distribution Substation Circuit Breakers and Transformers
  - Lack of power testing facilities to test new technologies for increased power flow and investment to drive development of better diagnostics for breakers and transformers
- Workforce Effectiveness
  - Lack of commitment and investment to develop comprehensive training and knowledge capture
- Right of Way
  - Lack of investment in vegetation management R&D and lack of understanding of the impact of vegetation-management-caused interruptions
  - Lack of competition between vegetation management firms to drive R&D

How activity will fill capability gaps and overcome barriers

DOE will bring together manufacturers, utilities, universities, national laboratories, and consultants through funding of these collaborative efforts.

Recommended investment horizon and development strategy

The technology gaps identified in the aging infrastructure area all fall in the short- to mid-term investment horizon and can be resolved in the 1- to 5- year time frame.

- Underground Cable
  - Develop partnership of utilities and diagnostic providers to work with R&D application center to significantly enhance existing cable diagnostic tools
  - Develop DOE/manufacturer partnerships to advance the state of the art in trenchless cable technologies
- Wood Poles
  - Identify most promising diagnostic technologies and support further development of developer's equipment
- Distribution Substation Circuit Breakers and Transformers
  - Drive the creation of power testing facilities to enable R&D
- Workforce Effectiveness
  - Develop partnership of utilities to identify training gaps, needs, and fill gaps
- Right of Way
  - Identify vegetation management practices throughout the United States, select organization to study impact of vegetation management on reliability, and develop partnership with regulators, utilities, and public advocacy groups

2.3.1.2. Fault Locating, Prediction and Protection

The capabilities of detecting and locating incipient and actual faults on a distribution system (at the substation or out on the line) need to be developed. This fault detecting/locating system would consist of a sensor to monitor voltage and current to be coupled/transmitted to an IED (microprocessor) that can in turn operate a sectionalizing device. The system will also need to interface with the outage management system.

Problems to be addressed, and end state of each problem once addressed

Need systems/tools to predict, detect, and physically locate faults on distribution systems.

Specific technology needs and their performance requirements

- Compatible with industry standards
- Integrate with existing electronic controls, devices, or relays
- Sensors that capture current and voltage signals without distortion
- Time synchronized phase angles
- Compatible with existing switching equipment
- Recognize direction of current (for distributed resources on circuit or network)
- Capture waveform
- Signature recognition for prediction of imminent equipment failure, e.g., cable failure

Current science and technology capabilities

- Fault distance location
- Incipient fault detection

- Multi-function microprocessor-based relays and controls
- High impedance fault detection

Existing capability gaps (between current and needed states) and barriers

- Determine specific lateral that fault is on (present technology only knows impedance; it may be down many branches)
- Coordination of detection and location technologies
- Ability to interact with outage management systems
- Inexpensive sensors

How activity will fill capability gaps and overcome barriers

DOE will bring together manufacturers, utilities, universities, and consultants through funding of this collaborative effort.

Recommended investment horizon and performance targets

- Year 1: develop scoping document and facilitate consensus process
  - Summarize current technology
- Year 2: develop hardware sensor and processor
  - Develop a current sensor with a price less than $300 and that is immune to interference
- Year 3: develop hardware integration
  - Develop and deploy replacement upgrade hardware for existing equipment
- Year 4: test bed demonstrations
- Year 5: actual pilot circuit deployment
- Pilot installation at a minimum of 3 sites, with six-month operations under the monitoring mode and 6-month operations live

2.3.1.3. DER Integration

Problems to be addressed, and end state of each problem once addressed

- Multiple DER interactions and stability issues
- Coordination and interoperability of multiple DERs with multiple applications/customers
- DER protection coordination with network protector
- DER cost and reliability improvement and standardization
- DER impact on distribution system and penetration limits
- DER-friendly distribution system
- Seamless integration of DER with the distribution system to improve overall grid efficiency and reliability
- Autonomous DER operations

Specific technology needs and their performance requirements

- Standardized and low-cost interconnect interface equipment
- Advanced control algorithms for multiple DERs and distribution systems coordination
- Solid-state switching for fast DER protection in coordination with network protector
- Integration and optimization of energy storage for renewable DERs
- Methodology to determine maximum DER penetration in distribution system
- Standard guide for DER penetration and grid impact

Current science and technology capabilities

- Single vendor DER site implementation
- Customized DER installation
- Limited streamline process for DER to connect to distribution system
- Limited penetration due to unknown penetration limits
- Independent DER operation

Existing capability gaps (between current and needed states) and barriers

- Cost
- Reliability
- Standard guides
- Flexibility (scalability)
- No DER coordination with distribution system operation
- Multiple vendor DERs integration
- Distribution system is not friendly to DER
- Customized design and engineering studies
- Non-standard hardware and protocols for different vendors

How activity will fill capability gaps and overcome barriers

- Lower cost
- Develop standards to ease barriers
- Provide technical basis for contractual agreements
- Standardize hardware to increase reliability
- Optimize generation/load/storage
- Optimize distribution system design with DER
- Develop methodology to define penetration limits
- DER with adaptive control and local intelligence

Recommended investment horizon and performance targets

Mid-term (3-5 years) with targets of:

- 30% cost reduction
- 50% reliability improvement
- 20% more DER penetration
- Impact of DER standard guides on distribution system in 3 years
- DER and distribution system certification program in 5 years

2.3.1.4. Meeting Customer Power Quality (PQ) Requirements

Problems to be addressed, and end state of each problem once addressed

- Utility delivery system methodology and hardware has not evolved with new customer loads and needs
- Increasingly sensitive customer loads
- Increasing gap in level of service between utility delivery system and customer expectations
- No corresponding rate structure for providing multi-tier levels of service to customers
- Impact of nonlinear electronic loads on PQ for neighboring loads, and on overall delivery system
- No systematic approach (defining line) for addressing customer availability and PQ issues, i.e., resolution at delivery system level vs. at customer side

Specific technology needs and their performance requirements

Performance Standards

- Define minimum level of service by customer class for power quality and availability for utility delivery system
- Define premium levels of service at point of common coupling
- Define performance standards for load devices that address overall economics of PQ (utility vs. manufacturer vs. customer cost)

Technology

- Monitoring and control of reactive power
  - Short-term: low-cost hardware for upgrading and automating shunt capacitors
  - Longer-term: variable dynamic reactive power via power conversion interface of DER devices
- Incorporate energy storage for distribution delivery support
- Develop more resilient and responsive loads with better ride-through capabilities
- Develop seamless DER interconnection systems that can provide both critical load support and distribution delivery support

- Self-healing and correcting fault protection that can be coordinated with energy storage technology to provide PQ and availability gains
- Develop more resilient distribution infrastructure topologies that can be transitioned into the existing infrastructure

Current science and technology capabilities

Distribution systems with legacy designs from pre-electronics era.

Existing capability gaps (between current and needed states) and barriers

- Level of service limitations of current distribution delivery system and more demanding customer requirements
- Lack of distribution standards that reflect today's customer needs and power electronic capabilities
- Lack of cost-effective dynamic variable reactive power control
- Sensitive, nonlinear customer loads
- Need low-cost and high-performance power conversion-based DER interface technologies and application strategies
- DER systems lack capability to contribute to overall system PQ

How activity will fill capability gaps and overcome barriers

- Establish consistent standards and requirements to address PQ issues
- Lower costs
- Higher capability DER, storage, and reactive control solutions that address PQ issues

Recommended investment horizon and performance targets

Near-term (1-2 years) for standards and roadmap efforts; near- to mid-term (3-5 years) for technology development and deployment:

- 2006: establish level of service standards based on current technologies, and set performance standards for 2010 and 2030; establish customer load standards
- 2007: develop roadmap for transition of the distribution delivery infrastructure from its current state to the systems of 2010 and 2030; establish operating strategies, and standards for deploying high penetration levels of energy DER for the grids of 2010 and 2030
- 2008: develop and deploy cost-effective technologies for automating existing reactive power assets; achieve 30% reduction in power conversion cost; develop and deploy high-performance power conversion systems that allow seamless interfacing of energy storage and DER assets
- 2010: develop and deploy cost-effective dynamic reactive power supply systems
- 2010-2030: develop and deploy advanced self-healing protection systems on 5% of distribution system by 2010 and 100% by 2030

2.3.1.5. Advanced Operating Strategies

The future electric system must become optimized using new strategies and technologies to balance customer needs for reliability and low cost within the economic realities and constraints of today's utilities. Accomplishing this goal of optimization will require dramatically enhanced and in some cases fundamentally different operating strategies and tools. Planning and operation of the future system must capitalize on the advances in inexpensive telecommunications, power electronics, and advances in information and control systems. New tools and technologies are needed to seize all opportunities that lower the cost required to operate the system and achieve performance targets. The new tools not only need to take advantage of new hardware and software, but also need to include a broader set of technologies such as time-of-use pricing and variance in reliability needs of different customers over time.

The focus of this RD^3 activity is on identifying the nature and basis of some of the key technical areas, and associated project topics, where dramatic advances and fundamentally new operating strategies and tools will be required.

Problems to be addressed, and end state of each problem once addressed

The major challenges and opportunities are identified in terms of the end states, with discussion of principal topics requiring attention.

- Dynamic optimal coordinated system operation
  - Real-time state estimation. Presently only minimal information is available on system status, and rarely in real-time. This is needed for dynamic operation and optimization.
  - Real-time load information. More electronic metering with open communication is necessary for monitoring real-time customer loads. Since customers will be a part of the operation of the distribution system, information regarding their loads and capacity to contribute to power system operation will be essential.
  - Real-time DER information. Effective use of DER requires real-time information and communication for improved operation of the distribution system and to provide enhanced customer service.
  - Real-time system configuration. Having real-time information is of limited value unless one can also effect changes in the operations of distribution system components, including power delivery, generation, and end use. This technology is generally not used at the distribution level today.
  - Adaptive circuit protection schemes. The vast majority of distribution systems have no capacity to alter their protective strategies, schemes, and associated set points. Dynamic operation of the distribution system or self-healing system will require protection systems that can adapt and change in response to conditions and control instructions.

  - Dynamic optimal voltage/VAR management. Limited approaches to voltage and reactive power management are used on the distribution system operation today. The ability to implement dynamic management of these electrical attributes is necessary for management of delivered service and costs incurred, and will be valuable in support of transmission level reliability.
  - Multiple objectives for optimization. Future distribution operations will require the arbitration of operational strategies (e.g., safety, reliability, cost, etc.) dynamically, to meet ever-changing needs and opportunities.
  - Management of diverse resources. Customer loads, generation, and storage are not managed or operated in a manner to benefit the distribution grid. They represent significant future contributors to participate in relieving heavily loaded or emergency situations. Again, the ability to communicate with these devices and integrate the data from them will require open architecture and standardization of data transfer.
  - Validation of services and resources (e.g., schedules settlements). Other than service entry metering (in most cases recorded monthly), there is little capability to measure and validate customer participation in electric power system operation. The various AMR systems being installed need to be able to integrate the data with DER, etc. for maximum usefulness and data integrity.

- Alignment of customer and distribution operating behavior and strategy
  - Contracts and negotiating vehicles for dynamic operation. Rate structures should enable consideration of the myriad of potential benefits that could be provided by dynamic participation of customers in grid operations. Utilization of customer assets for distribution system operational benefits will require compensation, and a means to establish fairly what the value derived might be, as well as rate compensation/incentives for distribution system operators to enhance/utilize DER systems. Distribution system level real-time power markets may be required to meet these needs.
  - Integration and interaction with multiple component control systems. There should be operational interaction between customer load control systems and those of the utility (including between utilities serving in adjacent areas). Integration of these typically automatic operating systems will be required to enable trusted participation of customer resources in grid operations.

- Test beds
  - Realistic exploration of extreme operating environments (push the limits, drive to failure) to allow examination of extreme operating strategies, particularly those employing new distribution technologies and customer assets. Test beds enable consideration of operating strategies employing massive information sharing and associated communications architectures and operational strategies that do not now exist. New/upgraded test beds need to be instituted.

  - Information sharing on existing development efforts. No broadly focused, organized efforts exist (beyond general technical society committee activity) to share information on existing and planned deployments of components and elements of the distribution system of the future, and barriers to such information sharing have yet to be addressed.

- Economics/Physics Modeling and Planning
  - Estimating and validating the full spectrum of potential benefits. Establishing an economic case for incorporation of advanced technologies and operating strategies is difficult due to limited tools for estimating costs. Business models incorporating multi-stakeholder value streams are needed to address the distribution system of the future.
  - Managing for new realms of uncertainty. The spectrum of uncertainty, already economically uncomfortable for electricity markets and utilities, will increase as customer participation in electric system operations becomes possible.
  - Systemic benefits. Allocating benefits and costs is difficult, particularly under new paradigms of real-time pricing, customer participation, and the capacity for customer and distribution system assets to provide local and global grid reliability or service support. Incentives for investment in systemic benefits need to be developed for increased utility participation.

Specific technology needs and their performance requirements

- Communication and data interface standardization for integration of massive new data flows independent of media (explore available initiatives such as MultiSpeak)
- Distribution operations optimization tools
- Near-real-time tools for validation of services and resources (metering, monitoring, etc.)
- Customer tools for participating in coordinated operation (contracts)
- Planning tools that enable exploration of a broad spectrum of options (test beds, optimization tools development)
- Device and system performance data (device reliability, mean-time-to-failure, etc.)
- Training tools and simulators for operators and planners

Current science and technology capabilities

Core technologies exist to varying degrees, but additional development, testing, and evaluation are required.

Existing capability gaps (between current and needed states) and barriers

Development and proven application and demonstrations of technologies identified above. Physical test bed permits validation of performance. (See the "Problems" section above.)

How activity will fill capability gaps and overcome barriers

Successful development and demonstration is essential to deployment.

Recommended investment horizon and performance targets

Test bed development in 2 years; testing for 3 to more than 5 years; development of new tools or adaptation of tools (from other industrial environments) from 3 to more than 5 years

- Communication and data interface standardization for integration of massive new data flows (media independent)
  - Draft standard in 3 years, complete standard in 5 years, and deployment at 10 sites in 6 years
- Distribution operations optimization tools
  - Prototypes in 2 years, demonstrations in 5 years, and deployment at 10 sites in 7 years
- Near-real-time tools for validation of services and resources
  - Prototypes in 3 years, demonstrations in 5 years, and deployment at 10 sites in 7 years
- Customer tools for participating in coordinated operation
  - Prototypes in 2 years, demonstrations in 4 years, deployment at 10 sites in 6 years
- Planning tools that enable exploration of a broad spectrum of options
  - Prototypes in 2 years, demonstrations in 4 years, and deployment at 10 sites in 6 years
- Device and system performance data
  - Prototypes in 2 years, incorporated in demonstrations in 4 years, and deployment at 10 sites in 5 years
- Training tools and simulators for operators and planners
  - Prototypes in 4 years, demonstrations in 5 years, and deployment at 10 sites in 6 years

2.3.1.6. Improved Infrastructure Components

Problems to be addressed and end state of each problem once addressed

1. Encourage new system configuring and reconfiguring capabilities (microgrids, looping circuits, etc.).
2. Move from analog to digital world.
3. Expand and update utility distribution communication infrastructure.

Specific technology needs and their performance requirements

For Problem 1:

- Identify new configuration concepts achievable in 5-year time frame.

- Establish mini-test-bed facility to validate them (available by end of CY2005).
- Select a system of the future concept as a target to guide work. Consider a competition to do so.

For Problem 2:
- Replace electromechanical with new power electronic devices.
- Enable distributed intelligence.
- Increase system functionality.
- Focus on protection first—enable other things. Have fully integrated next-generation concept ready in 5 years.

For Problem 3:
- Full coverage of dense areas within 5 years using suitable media that will last for the long term (e.g., fiber). This is an ideal goal. In reality, as much additional coverage of dense areas as possible should be sought over the next 5 years.
- Clarify roles to be played by communication infrastructure in less dense areas, and then build the appropriate infrastructure.
- Encourage migration to open communication architecture standards.

Current science and technology capabilities

Relating to each problem area above:
1. Very basic, simple designs with little flexibility and intelligence.
2. Existing body of distributed computing and microprocessor-based equipment.
3. Vast body of existing communication media (wireless, satellite, fiber, lease lines, PLC, others).

Existing capability gaps (between current and needed states) and barriers

Relating to each problem area above:
1. Need more robustness and resilience; changes in electrical architecture and protection, and more widespread use of IEDs and distributed communication and control; increased security; and enabling functions such as two-way power flow, DER integration, more safety, and more redundancy.
2. Solid-state relays and switchgear are available, but there are still cost reduction needs. Comfort level of users needs to be raised by field experience. Legacy systems need to be operated for the remainder of their useful lives. Not all new equipment has been conformed to open communication architecture standards yet.
3. How to motivate utilities to invest in new equipment while getting remaining value out of existing assets. How do we enable them to finance the additions and changes?

How activity will fill capability gaps and overcome barriers

Relating to each problem area above:

1. Need to develop new IEDs where voids exist, and encourage use of the concepts. Mini test facility allows rapid trial and shakeout of configurations and reconfiguring capabilities.
2. Take existing system (analog) and put on accelerated depreciation schedule. Put new equipment on appropriate depreciation schedule based on its expected life and state of the art. New business opportunities (non-exclusive or monopoly-based) for regulated utilities that encourage use of the new technologies.
3. Regulators must allow financial mechanisms via rates, borrowing, depreciation, etc. Need regulated business tools, like rate of return, new revenue options, new cost options for higher risk options, etc. Need to encourage development and adoption of open communication architecture standards, such as IEC 61850 body of standards. Use open protocols borrowed from other industries. Need low-cost broadband all the way to end use, security models that support pervasive communications, and backwards compatibility with legacy systems.

Recommended investment horizon and performance targets

For Problem 1:

- By end of CY 2005: test facility ready
- 1-3 years: competition for target concept
- 3-5 years: new concepts for IEDs and configurations

For Problem 2:

- 1-2 years: for new installations and changeouts, use new concepts available now
- 3-5 years: same as above, plus additional new components that have emerged with the additional time
- Beyond 5 years: replacement of legacy systems

For Problem 3:

- For 1st bullet under specific technology needs: 1-5 years
- For 2nd bullet under specific technology needs: 1-3 years for communication role definition in less dense areas, followed by building the infrastructure
- For 3rd bullet under specific technology needs: 1 year and then continuing

Development strategy

For Problem 1:

Coordinate (to avoid duplication and ensure cooperation) with major utilities in United States and elsewhere (especially EDF and UK in Europe), EPRI, E2I, GridWise, Gridworks, etc.

For Problems 2 and 3:
Articulate clear and consistent vision to regulators, local rulemakers, utilities, EEI, NRECA, APPA, EPRI, vendors, standards groups, and other stakeholders. Develop and implement initiatives (and associated schedules) with these entities. Seek loaned employees from these stakeholders to help do this. Highlight successes in publications.

2.3.2 Timeline and Key Performance Targets

Key performance targets with associated schedules for each high-priority advanced distribution technologies and operating concepts RD^3 activity are depicted in Figure 2.3.2.1.

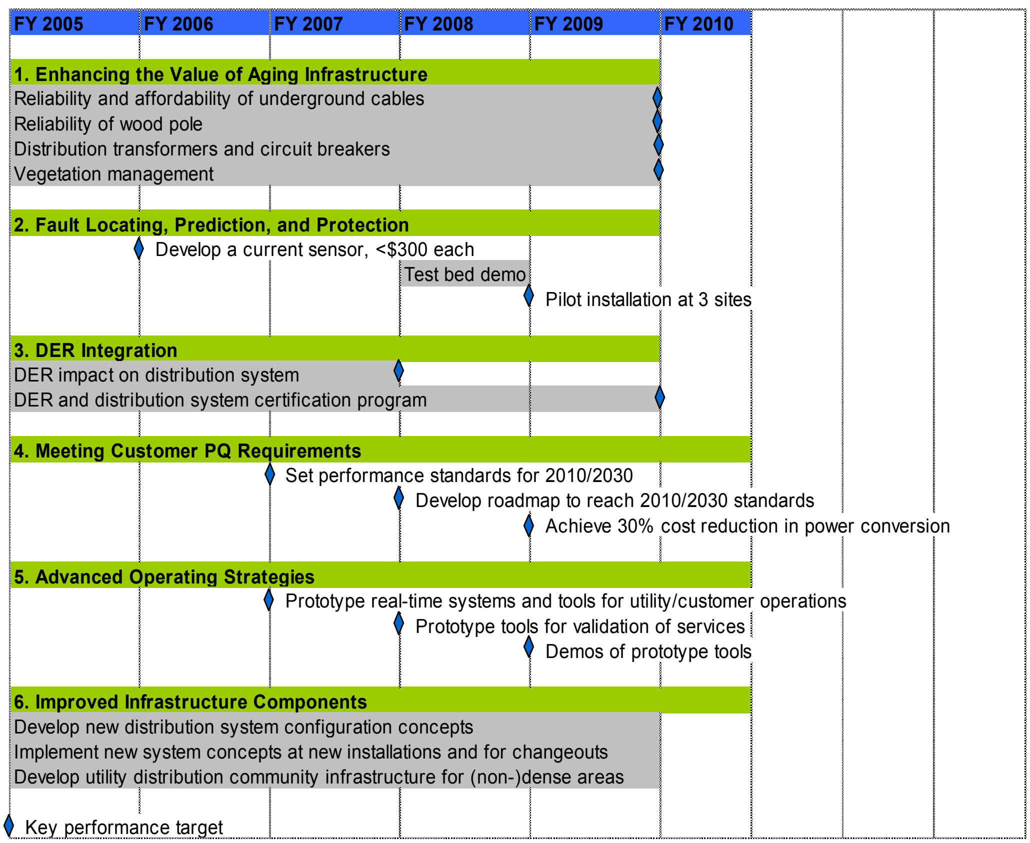

Figure 2.3.2.1 Performance Targets for Advanced Distribution Technologies and Operating Concepts RD^3

2.4 Modeling and Simulation

This Technical Area addresses modeling and simulation development to support distribution system planning and its optimal operations, including responsive measures for contingencies and disturbance events. The overall problems and needs addressed by this Technical Area include:

- Quantification of distribution problems/solutions in financial terms
- Data verification/validation and maintenance
- Data conversion to "information"
- Non-standardized data structures
- Common analysis integrated architectures

Data resources are a major focus of this Technical Area, which includes open standardization of data and design environments, data integration and mining, data integrity/authenticity/security, etc. This Area also focuses on technologies associated with better utilization and management of DER in distribution operations. In general, this Technical Area groups its technology needs into the three topical areas below.

- Real-time Modeling and Simulation
  - System state estimation
  - Optimal operations
- System Planning
  - DER modeling
  - Reliability-based planning
  - Financial models
- Facilitate Industry/Government Collaboration in Modeling & Simulation
  - Common data structures
  - Collaborative design and analysis environment
  - Standardization

2.4.1 High-Priority RD^3 Activities

Six major activities were identified in the multi-year RD^3 planning workshop. They are summarized in Table 2.4.1; a more detailed description of each activity follows in the ensuing sections.

Table 2.4.1. High-Priority Modeling and Simulation RD3 Activities

Problems to be Addressed	Technology Needs	RD3 Activities
Lack of a collaborative software development environment to leverage all stakeholder efforts and share data resources	Development of collaborative analysis and design environment, using state-of-the-art supercomputer, in an easy to use format for stakeholders	Collaborative Analysis, Design, and Operations for Energy Systems (CADOE)
Proprietary, incompatible, and non-interoperable data formats in various software tools used in distribution systems	Development of standard data format and structure as a common tool or translator for seamless data transfer involving various tools used in distribution and generation/transmission systems	Standard data structures to support system analysis and planning
Lack of analysis tools to balance risk, system reliability, financial investments and economic returns, and customer impacts	Comprehensive model to allow distribution utilities to make sound technical/investment decisions on optimum projects for system expansion or improvement	Modeling electric performance metrics along with economic/customer valuation
Operational assessment of DER technologies with the distribution system over time, including modeling its impact on a regional system	Modeling and optimizing the impact of DER on distribution system reliability, cost, security, protection, and operation	Modeling new and existing DER technologies on the distribution system
Inadequate end-use/temporal resolution in available measured loads; and inability to accurately forecast the impact of new external conditions on customer loads	Modeling tools that enable utilities to model the magnitude, shape, and response of loads as functions of price signals, weather conditions, etc.	Load prediction and modeling tools
Understanding of the monetary value that customers place on reliability	Development of a customer outage cost database, through extensive surveys of various customer categories	Value-based reliability

2.4.1.1. Collaborative Analysis, Design, and Operations for Energy Systems (CADOE)

A software system referred to as **C**ollaborative **A**nalysis, **D**esign, and **O**perations for **E**nergy Systems, CADOE, is proposed. CADOE will facilitate, and in many cases enable, collaborations among electric utilities, gas utilities, regulatory and policy making agencies, suppliers, integrators, aggregators, and customers. CADOE is envisioned to encompass simulation, analysis, alternative design evaluation, training, and real-time operations support.

With CADOE, a communications researcher would have readily available, realistic models of distribution systems for testing of new communication concepts. The researcher could attach any type of communication objects and algorithms to the selected CADOE distribution system model. The researcher would decide if any other users of CADOE should have access to his work. For example, there may be an industry investigating the ability to use distributed agents for control, and the industry workers would like to experiment with the new communication concepts as an enabler of their new distributed agents.

CADOE would leverage the efforts of workers from diverse areas, allowing them to achieve more in shorter periods of time. Once new models with public access are installed in CADOE, they are available to all future efforts. Via CADOE's asset manager, it will be possible to build, load, download, merge, and incrementally update models. Thus, workers from many different areas will be able to evaluate how their ideas work together and obtain responsive feedback on their individual ideas. Such synergy sparks advancements and great solutions.

Suppliers of both software and hardware to both customers and utilities could use CADOE to test and demonstrate their concepts and products. Integrators could use CADOE to test the integration of products, avoiding the much larger expense (often paid for by customers) associated with discovering problems in the field.

CADOE would enhance communications and understanding among the stakeholders. It would provide consistent results across alternative evaluations, allowing utilities to test and demonstrate their concepts on a medium trusted and shared by regulators. CADOE would create a community of stakeholders, providing decision support across the community. CADOE would provide a reliable data source, a common platform for validation and verification, would reduce duplication of effort, and would leverage the efforts of all stakeholders.

CADOE software would use a client/server architecture. It could run over a private network at a single physical location, or over the Internet. A standard, secure messaging scheme would be used. A component-based architecture based on the generic programming paradigm would be employed. Thus, modeled objects would be stored in containers, and algorithms would process the objects via iterators. CADOE would provide an open architecture that would allow any CADOE user to add applications, data sets, and functionality. Previously existing software could be wrapped in CADOE defined interfaces and used in CADOE.

CADOE would include a "piping functionality" that makes it convenient to convert between common model formats. It would be possible to invoke the piping functionality either through a user interface or programmatically. Standard formats (such as Multi-Speak) and widely used model formats (such as from GIS vendors) would be maintained in the CADOE asset management library.

The same CADOE that is used for analysis/design collaborations could help plan and manage real-time emergency operations. CADOE simulations could initially help with practicing for emergencies, and then with decision support during actual emergencies. To reach the ultimate vision of a CADOE that is responsive during large-scale emergencies, a supercomputer software layer with real-time measurement inputs would be needed. The supercomputer implementation would be transparent to CADOE application developers.

Recommended investment horizon and performance targets

The development horizon for CADOE is envisioned to be three years and consists of two phases. Eighteen months of development are proposed for each phase. Two major parallel paths are proposed throughout the project. During the initial nine months of development, one path would address a rapid prototype development and the second path would consist of requirements gathering that employs use case goal modeling. The final task of the goal modeling would address prioritizing the desired CADOE functionality.

Once the CADOE rapid prototype is available, it would be provided to selected collaborations for testing and evaluation. One such collaboration would occur between a utility and a regulatory agency. Another such collaboration would take place between a national lab, a private research organization, and private industry. In parallel with the collaborations, high priority functions as identified by the goal modeling would be implemented. It is envisioned that one of these functions would be the handling of real-time measurements. At the end of Phase I, lessons learned from the selected collaborations would be documented, and the first production version of CADOE would be released with realistic models populating the data schema.

During Phase II additional functionality would be released for testing every six months. This phase would also tackle the software layer that implements a CADOE server on a super computer.

2.4.1.2 Standard Data Structure to Support Modeling, Analysis, and Integration of Energy Systems

The problems to be addressed, and the end state of each problem once addressed:

- The purpose of this activity is to develop and implement a comprehensive, common data structure/schema (e.g., integration framework) to support modeling, analysis, and integration of energy systems. One of the principal challenges in the representation and exchange of power system data is passing the data between various software tools. The software tools use different models of the power system and a variety of data formats. For example, widely used power system simulation tools, such as PSS/E and CYMDist, use their own proprietary data formats. Moving data from one format to another format requires some data translation, which is necessary to resolve several issues including topology format, unique component identifiers, physical characteristics, and identification of a specific device.
- Distributed Common Information Model (DCIM) should be designed to support distribution with potential/desirable extension to the entire transmission (T), generation (G) and distribution (D) system (T&G&D). It should represent all the major and minor components in an electric utility including classes and attributes as well as their relationships (e.g., all the distribution network characteristics).

- Extensible Markup Language (XML) should be adopted for formatting the model data/information in an open, extensible manner.
- It is preferred that any software tool and data at the distribution level be in DCIM XML format. This type of format should allow easy sharing/exchanging of data between stakeholders (vendors, developers, utilities, etc.).
- Resource Description Framework (RDF) can be used as a common schema to describe the DCIM power system basic model for the distribution tools; XML could be used to format the energy system data/information.
- Future simulation tools should be able to read the DCIM data directly without any translation, perform an analysis, and then output directly in the same DCIM format. This will require a full integration of DCIM tools with inherited software.

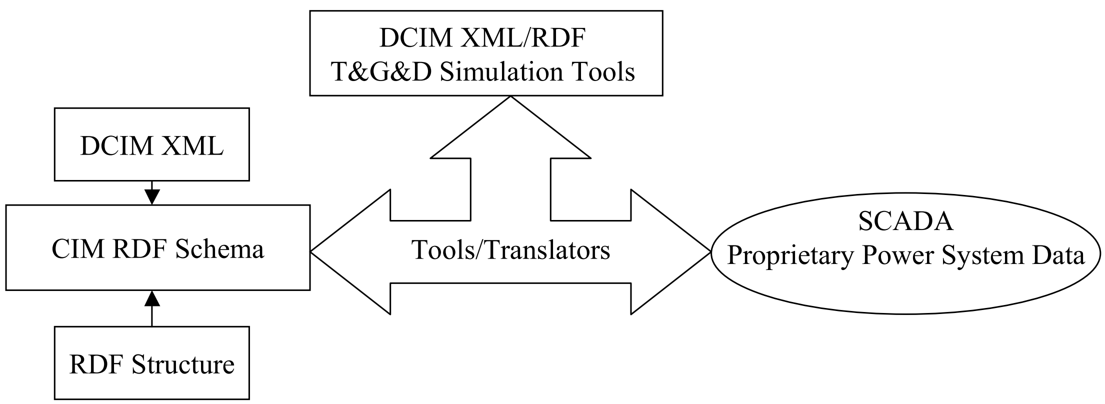

Figure 2.4.1.2.1. Schematics of DCIM XML/RDF Schema Implementation

Specific technology needs and their performance requirements

- Standard data format and structure (schema) to allow communication between various software tools globally (T&G&D level) or locally (for example, D level). Specific technology needs and modeling issues include: (1) large information/data model up to 100 million components; (2) radial and network configurations; (3) allowing dynamic, transient analyses with restoration/reconfiguration/protection/emergency-planned switching/etc. capabilities; (4) several external data sources with circuit data/information (primary and secondary networks) from the substation to the customer meter represented by geographic maps with a low number of components being tele-metered and tele-controlled; (5) modeling of multi-phase network with unbalanced 3, 2, and 1 phase lines, devices, and loads.
- The DCIM should have the following basic modeling requirements: (1) interoperable (e.g., exchange understandable information/data between applications in any computer system); (2) fast; (3) internet capable; (4) compact; (5) flexible; (6) comprehensive (capable of adding all the information/components/devices at the distribution level (e.g., specific devices such as regulators, reclosers, sectionalizer,

switches, etc.) and should reflect all the distribution network characteristics; (7) secure (encrypted); (8) open/ extensible for future upgrades and updates; (9) coherent with the DCIM specifications (to be developed); and (10) multi-phase connections (DCIM should represent multi-phase distribution lines, devices and loads) and features (unbalanced 3-, 2-, and 1-phase lines, devices, and loads). In addition, a major issue with the transmission level CIM model is that it is too low level (contains information about switches and circuit breakers) and using it for analysis purposes (e.g., load flow, security analysis) is too cumbersome. We would also need to overcome this problem in the DCIM model.

Current science and technology capabilities

Several open and proprietary data formats are available at the T&D levels (e.g., PSS/E, GE, IEEE, CIM for T&G), incompatible or not fully compatible/non-interoperable with the software tools at the distribution level.

Existing capability gaps and barriers

Capability gaps: Only two designs are available in CIM XML format (there is no design available for distribution power systems): (1) Electric Power Research Institute (EPRI) developed a CIM XML to provide a comprehensive power system data exchange format for T&G power systems and (2) an extension of CIM XML for the IEEE radial distribution test feeders was developed at Michigan Technological University and Mississippi State University.

Barriers: (1) Acceptance by utilities, vendors; (2) IP protection could be a problem for vendors; and (3) even after the introduction of DCIM-based simulation tools there could still be substantial embedded investment in software using proprietary formats.

Recommended investment horizon and performance targets

- 1-2 Yrs: Development of tools and translators
- 3-5 Yrs: Deployment/implementation/integration of tools and translators into the existing software

2.4.1.3 Modeling Electric Performance Metrics along with Economic/Customer Valuation

Problem to be addressed

Distribution owners and operators face a significant challenge to design and operate their systems in ways that optimize reliability, safety, efficiency, environmental impact, and financial requirements. Complicating this challenge more than anything else is the need to effectively forecast and measure a comprehensive set of electric reliability performance metrics that can be correlated with the monetary value electricity customers place on the quality of the electric service they receive. Without a value-based set of reliability performance metrics, there is no way for utilities to communicate information that can be visualized and understood by various stakeholders to make informed decisions. Solving this problem would help engineers, operators, managers, investors, and regulators make the strategic and tactical decisions that literally impact the lives and economic well being of our nation. The inability to project performance metrics and the inability to quantify or economically compare the value of various levels of performance for the impacted customers means that portions of distribution systems can easily become under funded or over funded. A more significant threat is that large areas of the nation's distribution system can be harmed if investors or regulators lack the ability to link proposed investments in distribution to the value achieved for customers.

Proposed solution

The DOE supports the development of both real-time and off-line modeling technology to provide planners and operators with the capability to optimize the distribution system by modeling performance metrics that measure risk, reliability, customer and employee impacts, and total system cost of ownership. The model output should be designed with robustness for experienced utility engineers. Frequently occurring events such as load growth, weather, storms, equipment failure, and engineering design and maintenance options should be easy to model so that alternatives can be compared. The new model also should provide non-engineering metrics and visualization outputs so that customers, investors, and regulators can understand the monetary value and incremental benefit to electric customers in addition to the resources required to achieve appropriate levels of reliability.

Specific technology and performance requirements

The proposed effort should first determine acceptable performance/reliability metrics that model risk, reliability, and total system ownership costs. Second, the model should quantify or relate reliability metrics to customer monetary value. The output should include multi-tiered value assessment of events such as power quality, momentary interruptions, sustained interruptions, voltage sag, and storm related outages by customer type.

- Model should run in both near real-time and for 1- to 5-year planning horizon
- Model input should include interfaces for GIS and network topology, including device files, customer-based interval load modeling, transmission/generation interface, distributed generation and load management, weather interface, and others
- Model outputs should include metrics and outputs for:
  - Risk (all hazards prevention/mitigation/recovery versus threat matrix)
  - Reliability (SAIDI, MAIFI, CAIDI, and others)
  - Power quality
  - Total owning costs (capital, O&M)
  - Customer impacts by customer type (costs, overall satisfaction, power quality)
  - Environmental impact (vegetation, visual, etc.)

- Visualization for non-utility engineers
- Transmission interface (VAR & Impedance)
- Recommendations for circuit optimization (capacitor settings, switch settings, etc.)

Current science and technology

Most distribution planners use engineering planning tools to model single points in time or events for a particular subsection of their system. These tools typically are labor intensive and do not project risk, reliability, and customer impacts. The current models do not adequately address the economic value of reliability to different customer types and also do not accommodate appropriate threat environments facing separate geographic areas of utilities that include weather, load variances, and the continuous changes in network topology that occur in a large distribution system. The current systems at best are inadequate for real-time operational use and also for performing longer-term assessments such as the impact a particular engineering design will have on reliability. Most utilities need new technology to effectively model load management, distributed generation, weather impacts, and dynamic power quality performance.

Gaps and barriers

The major gap is in evolving utility distribution planning from a simplified steady state model based on maximum forecasted load or special case load flow calculations, to a dynamic heuristic or rules-based model that provides insight into risk, vulnerabilities, reliability, power quality, and ultimate economic value delivered to customers. Without this information, utilities are unable to design and operate distribution systems with reliability performance linked to customer value. The two largest barriers are interfacing the data that exist in multiple databases across utilities and designing models that require modest resources to purchase and use. An additional gap is the need for analytical support for establishing reliability performance metrics that correlate to customer value that can be quantified in monetary terms.

Recommended approach to overcome gaps

DOE should fund model development on a generic utility data base format so that each model component can be developed for portability across different utilities. DOE can provide the expertise to model complex issues such as establishing how to quantify the value of reliability to various customer types. Performance metric calculations should achieve more universal acceptance using DOE in a collaborative role for multiple stakeholders. Each utility would then be able to focus their own efforts on the data interface and topology for their system rather than individually having to develop modeling technology for performance metrics that have little commonality. A design that can assemble existing utility information to develop network connectivity and topology overlaid on existing utility GIS systems would overcome a large barrier. Load data can be modeled using weather and existing SCADA data along with customer data. For example, the model should determine the true value of investments in reliability to stakeholders. For example, knowing the stakeholder value of a momentary interruption by customer type would allow more effective funding of reliability investments for different customer mixes across different geographic sections of the distribution system. A similar rationale would allow DOE support for modeling vegetation management to benefit the nation as a whole more effectively by deploying the proposed model in a format that allows customer mix, and regional geography, to meet the needs of multiple utilities and stakeholders.

Recommended development strategy

The first phase is to provide a forecast model framework that identifies performance metrics that can be economically used by utilities and that can be correlated and quantified by different customer types. The first phase should last no more than twelve months with at least one significant model output (vegetation management, for example) that correlates the performance measurement to customer value. This will allow utilities to install a useful model on a short time horizon. The remaining modules should be released addressing the required outputs over the next eighteen months. The near real-time model would then be set for release after three years.

The development scope would include the following:

- Assessment of variations of value based on geography, organization, markets
- Develop survey for stakeholders to establish model parameters and requirements
- Determine the tier of reliability components to be valued, i.e., momentary, sustained outages, weather impacts
- Common Customer Value database
- Performance target examples: optimal vegetation management impacts, determine replacement/repair strategy, distribution automation versus system expansion, storm response planning

2.4.1.4 Modeling New and Existing DER Technologies on the Distribution System

The problems to be addressed, and the end state of each problem once addressed

Modeling new and existing DER technologies on the distribution system and within microgrids. DER technologies include distributed generation (including combined heat and power), energy storage, demand response, and energy efficiency.

End State: A suite of modeling and simulation tools that integrates economic, engineering, and environmental analyses of DER technologies for any distribution system. The control of the DER should be within the context of a regional power system or market. These models should incorporate detailed engineering models of the distribution system. They should avoid such approximations as balanced power flows that result in models giving insufficiently accurate information needed for building the distribution system of the future that efficiently optimizes use of DER technologies and intelligent electrical devices.

Specific technology needs and their performance requirements

- Modeling tools should be able to be used initially for short-term and long-term analysis purposes. Eventually, these tools should provide the foundation for actual real-time operation models.
- Future real-time tools need "real-time" performance to allow for system optimization. The full potential of the "intelligent distribution system" has yet to be fully assessed, and appropriate operational protocols established. However, the models need to be more than just for testing *compatibility* of a DER technology with the distribution system. The models need to be helpful to DER *equipment design*, particularly regarding control schemes, so that manufacturers can provide DER equipment that can be of the highest possible value to customers, the distribution services provider, the regional power system/market, and society at-large.
- The models must incorporate DER operation data (energy import/export, costs, fuel, operational response such as to load changes and power output requirement, fault current, etc.).
- System operational parameters, line and electrical component characteristics, and configuration need to be included.
- Control/dispatch of DER in operations (real-time) following established operational objectives and constraints for the distribution system, as well as regional system/market protocols.
- Customer objectives and needs for use of DER in microgrids should be modeled.
- Planning for DER and distribution system enhancements should also be modeled.
- Reliability of DER equipment, distribution system components, and customer perceived reliability benefits/costs need to be explicitly modeled.
- Customer benefits/costs, distribution infrastructure costs, DER operating costs, and system losses will provide performance measures to evaluate the technologies.
- Environmental costs/benefits are also important performance metrics.
- System protection/stability and security are currently modeled, but modeling/simulation capability may need to be expanded to allow "plug and play" of alternative DER designs and load characteristic scenarios.

Current science and technology capabilities

- Existing tools have capabilities of steady state system power flows, short circuit analysis, unbalanced network modeling, protection system analysis, Monte-Carlo simulations, dynamic and transient stability, protection simulation and coordination, and power quality analysis.

- Customer loads in existing models are fixed.
- Existing tools can quantify capital and O&M costs.

Existing capability gaps (between current and needed states) and barriers

- Lack of capability for integration of economic/engineering/environmental analyses.
- Lack of accurate technical models of the distribution system, including physically based models of distribution system components as well as unbalanced, three-phase models.
- Failure to consider optimization of design and operation of DER. Existing standards do not allow optimal operation of distributed resources for distributed benefits (utility and customer). Also, DG manufacturers do not have the operational guidelines/protocols to optimize their equipment control designs.
- Operational tools fail to efficiently model impacts over time (such as 8760 hours) rather than just at a selected time (such as peak system loading). Detailed protection and stability analyses will be conducted for a given time and set of conditions; however, operational assessments are needed over time.
- Failure to model impacts within the context of the entire power system (for example, dispatch of DER could be based on electric generation and transmission system as well as on distribution system conditions.)
- Failure to model uncertainty (e.g., DER can be used to improve reliability to customers that have been isolated from the distribution system due to a distribution system fault. Doing so raises questions of control and stability of the isolated grid with multiple DG units.). Existing tools do not incorporate DER operational reliability data (probabilistic forecasting of intermittent sources).
- Failure to model different DER operating modes and objectives (e.g., a DER owner may offer dispatchable generation/load to the distribution system operator for power supply or voltage/VAR support. DER in microgrids will operate under customer-specific objective functions that have not been modeled with existing tools).
- Capability is lacking for environmental assessments of DER technologies based on selected operational scenarios and environmental constraints.
- Barriers to model development: Electric utility rates are kwh-based, and some DER technologies may have little benefit to distribution utilities (such as energy efficiency or load as resource) or may have negative business effects (e.g., CHP is a revenue threat.). Also, disaggregation of generation, transmission, and distribution ownership/operation raises barriers for tool building.
- Barrier: Multiple DER technologies are under development and may not have established or available parameters for modeling purposes.

Prioritization of capability gaps in need of an RD^3 activity

1. Development of a tool providing operational assessment of DER technologies within the distribution system over a specified period of time. Operation and assessment should integrate economics, engineering, and environmental factors.
2. Integration of the modeled distribution system into a regional system.
3. Addition of microgrid control and integration into the distribution system model.
4. Building automated planning tool with DER and distribution system expansion.
5. Enhancement of operational and planning tools to account for "smart-grid" technologies.

Recommended investment horizon and performance targets

- Near-Term: Assessment of existing models/simulations to determine technology gaps. Identification of possible short-term enhancements of existing models. Initial specification of a new suite of models/simulations. Identification of data needs. Cost: $2-$3 million per year.
- Mid-to Long-Term: Design, construction, and validation of a new suite of models/simulations based on "smart-grid" objectives. Cost: $3 to $5 million per year.

Development strategy

Key to the development strategy will be a collaborative design involving major stakeholder groups, such as: model/simulation tool developers (industry and academic), distribution businesses, regional system/market operators (including RTOs/ISOs), DER manufacturers and program designers, electricity customers, and state and federal agencies (including DOE, and utility and environmental regulatory agencies). Competitive development processes should be used. Broad steps in the process include:

- Identify stakeholder group. Form advisory teams.
- Identify objectives/needs for model/simulation tools.
- Conduct detailed gap analysis (tools and data).
- Develop model/simulation plans: short-term and long-term. Include data requirements.
- Facilitate short-term enhancements where possible.
- Construct new or redesigned tools.
- Conduct comprehensive validation testing.

2.4.1.5 Load Prediction and Modeling Tools

The problems to be addressed, and the end state of each problem once addressed

The technical challenge is to improve modeling of customer loads. Serving customer loads is the function of the distribution system, so understanding the nature of customer demand is fundamental to the processes of designing delivery systems and technologies to meet it. Models of customer loads are used for these processes when:

- actual measured loads are not available,
- available measured loads do not have the end-use or temporal resolution required, and
- demand needs to be extrapolated to conditions that have not been observed before (e.g., extreme weather, new customers, changed electricity prices, and new technology, utility programs, and rate structures).

Models of customer loads that embody detailed understanding of the timing, magnitude, composition, and drivers of customer demand will:

- Improve distribution planning and increase asset utilization.
- Quantify the potential of demand response and what part of it is achievable in practice (in light of customer behavior and technology characteristics).
- Provide accurate utility and customer economic benefit assessments of alternative system designs, configurations, and new demand-side technologies and other forms of distributed energy resources.
- Improve system recovery times after an outage.
- Allow reliability to be examined from an end-use services perspective (i.e., examine the benefits and means of differentiating reliability and quality of services among customers and end uses within a distribution feeder).
- Support analysis of the impacts of regulatory and tariff structures such as real-time prices, time-of-day prices, locational marginal pricing (LMP), ancillary service markets, and fuel switching.

Specific technology needs and performance requirements

In order to meet these objectives, customer load models must have the following characteristics:

- Models are required to predict residential, commercial, and industrial[1] end-use loads for individual customers as a function of time-of-day, day-of-week, and weather conditions.
- Load models must be capable of estimating loads at various time scales of interest: hour-by-hour, minute-by-minute, and second-by-second.
- To assess the full electrical impacts of loads on the distribution and transmission systems (voltage, harmonics, etc.), the models must predict loads in the form of their electrical characteristics, such as resistance, inductance, phase angle, inrush currents, etc.

[1] Industrial loads are highly idiosyncratic and therefore may not be amenable to modeling with any useful result. Measured data for them is also much more likely to be available (although not with end-use detail). Therefore, it is recommended that residential and commercial customer load models be developed first.

- To analyze alternate scenarios, the load models must accurately account for the diversity of loads as driven by:
  - customer class (e.g., for single family, multifamily, building type or SIC code for commercial)
  - customer characteristics such as number and income of occupants, etc.
  - end-use technology characteristics such as floor area, efficiency levels, and fuel types
  - curtailment or price signals received and their duration
  - rebound upon restoration and black start/cold load pickup after outages.
- To assess the impact of price signals on customer loads, the load models must incorporate customer behavior in the form of:
  - end-use elasticity as a function of price level and duration
  - the probability of response to a price or curtailment signal
  - response to and selection of various types of contracts/incentive structures: real-time, time-of-day, take-or-leave, LMP, and others
  - adoption of new technology to mitigate inconvenience and capture rate benefits.
- The models must be able to assess the impact of deploying various technologies and energy management strategies such as direct curtailment, customer load control, energy management based on price, distributed generation including combined heat & power (CHP) and building-cooling-heating-power (BCHP) systems, storage, efficiency, and renewables.
- The load models must incorporate the impact of technology upgrades on:
  - changing the shape, magnitude, and duration of electrical and fuel loads (including metrics for the reliability and probability of the change)
  - mitigating customer inconvenience (increasing the elasticity of end uses)
  - changing customer response to and selection of contracts and incentive structures
- Tools must be provided to calibrate aggregate modeled loads to match existing customer class load shapes from utility class load research data.
- Load models must interface to industry standard data formats and object model conventions where possible and appropriate. Where no such standards exist, all protocols used will be documented and openly available.
- Load models must undergo rigorous testing against published test cases.

Current science and technology capability

Distribution engineers use rules of thumb for typical peak demand for various customer types. These rules of thumb are based on a combination of experience and customer class load shapes from historical utility data (customer total load time-series data collected at 15- or 30-minute intervals). Unlike rules of thumb, the customer class data provides a time-series. However, neither provides any resolution of individual end uses. The class load data is supplemented by similar data from time-of-use utility billing meters, typically for selected large industrial and commercial customers.

Building simulation models have historically been used by utility demand-side management programs to estimate end-use loads. However, they typically focus exclusively on estimating heating and cooling loads as a function of building and equipment characteristics and presumed occupancy patterns. All other end uses are exogenous inputs that must be assumed. A few large end-use metering projects were conducted by utilities in the 1980s and early 1990s to support forecasting and demand-side management programs, and these can serve as the foundation for our understanding of actual end-use loads and aspects of customer behavior. Data from new automatic meter reading and load management programs at utilities can supplement these as new sources of end-use data.

Existing capability gaps

Utilities and researchers rely on historical data and lack the ability to accurately estimate the impact of extreme conditions or new technologies, programs, markets and price signals on customer loads. Information about the end-uses composition of loads is seldom available and then only as raw data or simple averages rather than comprehensive models. Existing data sources provide loads in watts, but the electric characteristics of the loads are not incorporated except as rules of thumb. The ability to model new technologies coupled with distribution system operations and power flows and with new markets or price incentives does not exist. For lack of accurate end-use resolution, we are unable to model the linkage between gas and electric demand impacts for CHP/BCHP systems with the end-use loads that they serve. Inconsistent data structures and interfaces impede model development and use.

How activity will fill gaps

The proposed research will provide open source/open protocol load modeling tools with the characteristics listed previously. They will be integrated with electrical load flow models and also available for stand-alone use or incorporation into other tools. This will provide utilities, researchers, technology developers, and policy makers with the tools for performing sensitivity assessments regarding technology impacts, investment strategies, regulatory strategies, rate cases, etc.

Recommended investment horizon and performance targets

DOE investment is required. The recommended investment horizon is near- to mid-term.

A general development strategy with performance targets is:

Establish load flow modeling collaborative	6 months
Develop interface protocol and data standards for electrical models	12 months
Develop customer characteristic and load shape database	12 months
Develop residential modeling tools	18 months
Develop commercial modeling tools	24 months
Develop load aggregation tools	24 months

Develop economic modeling protocols	24 months
Develop pricing behavioral model	24 months
Establish test cases and validate models	36 months
Commercialize models	36 months

Budget: ~$2M annually for three years.

2.4.1.6 Value-based Reliability

Even if models were developed that could reasonably forecast changes in reliability metrics, another major problem needs to be solved and that is valuing reliability. For distribution owners to determine the proper (optimal) investments to make requires a clear understanding of the monetary value that customers place on reliability. Without this understanding, the distribution owner will most likely either over invest or under invest. Refer to Figure 2.4.1.6.1 to understand this qualitatively.

For owners who over invest, point O on the investment (reliability) curve, the reliability is very good, causing the customer outage costs to be very low. In this case, the outage costs are lower than what the customers would be willing to take if given the option. For owners who under invest, point U on the investment (reliability) curve, the reliability is very poor, causing the customer outage costs to be very high. In this case, the outage costs are higher than what the customers would be willing to take and they most likely have been complaining for years. The optimal level of investment occurs at the intersection of the investment curve and the customer outage cost curve.

As an example of the cost of poor reliability, refer back to the August 14 Northeast blackout. What did this cost the U.S. and Canadian societies? Numerous articles quote the price tag to be tens of billions of dollars. This would suggest that significant amounts of money need to be invested in the electrical infrastructure, but how much? To help distribution owners, and transmission owners, determine the optimal level of reliability required by customers will require development of a sophisticated customer outage cost database.

This information will most likely have to be determined through sophisticated surveys. However, the surveys cannot be developed until the various categories of customers have been identified (i.e., residential, small commercial, large commercial, industrial, hospitals, financial institutions, etc.) along with the various categories of reliability (i.e., momentary interruptions, one-hour interruptions, eight-hour interruptions, one-day interruptions, one-week interruptions, etc.). Also, research will need to determine if the value of reliability will vary by geography, by temperature, by season, etc. If this database could be developed, then distribution owners would be able to determine the optimal level of reliability required by its customers.

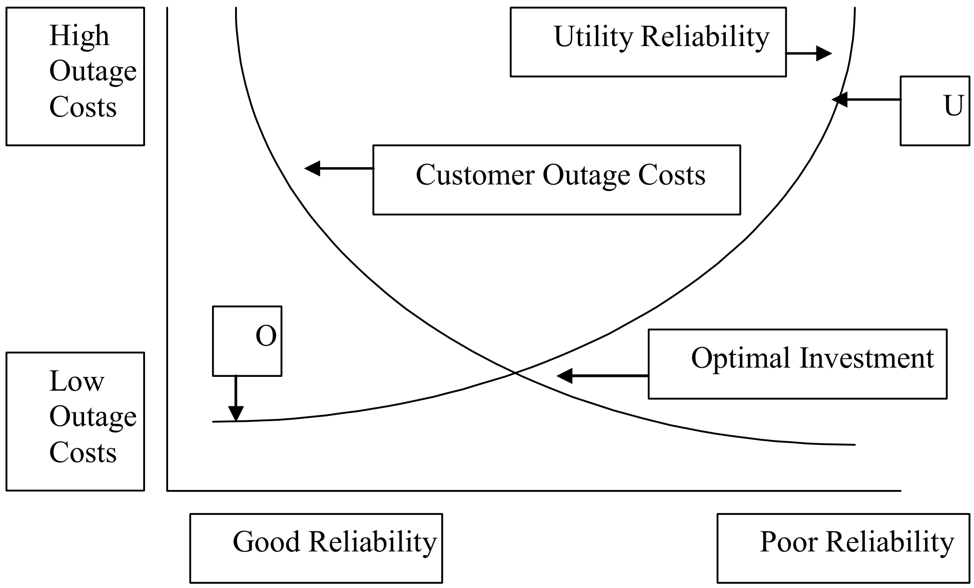

Figure 2.4.1.6.1 An Example of Outage Costs vs. Reliability Investments

2.4.2 Timeline and Key Performance Targets

Key performance targets with associated schedules for each high-priority modeling and simulation RD^3 activity are depicted in Figure 2.4.2.1.

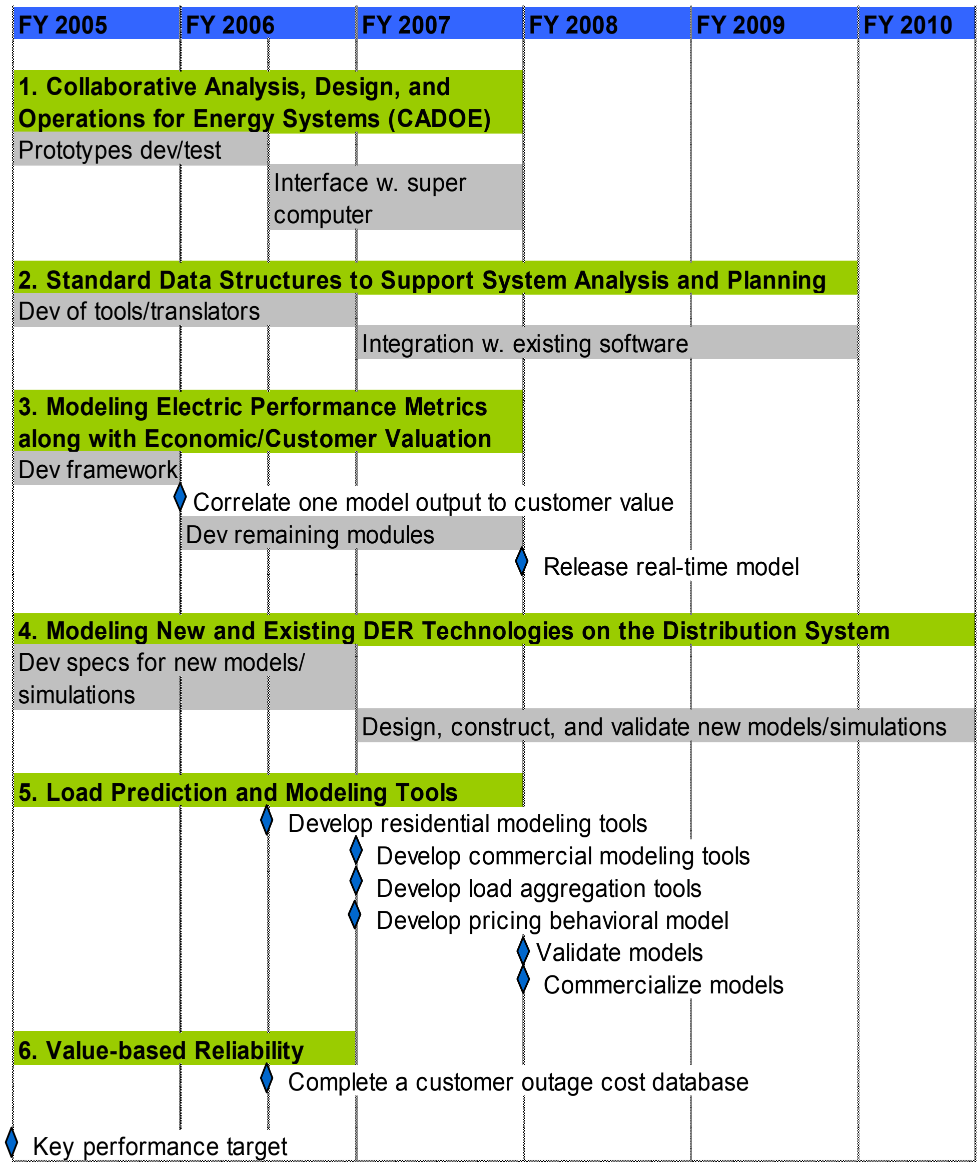

Figure 2.4.2.1 Performance Targets for Modeling and Simulation RD³

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List of Acronyms

AMR	Automatic Meter Reading
ANSI	American National Standards Institute
APPA	American Public Power Association
B2B	Business to Business
BCHP	Building Cooling, Heating, and Power
CADOE	Collaborative Analysis, Design, and Operations for Energy Systems
CEIDS	Consortium for Electric Infrastructure to Support a Digital Society
CHP	Combined Heat and Power
CIM	Common Information Model
CTC	Concurrent Technologies Corporation
D	Distribution
DCIM	Distribution Common Information Model
DER	Distributed Energy Resources
DG	Distributed Generation
DHS	Department of Homeland Security
DNP	Distributed Network Protocol
DOE	U.S. Department of Energy
DSL	Digital Subscriber Line
DSM	Demand-Side Management
EDT	Electric Distribution Transformation
EEI	Edison Electric Institute
EERE	Energy Efficiency and Renewable Energy
EMS	Energy Management System
EPRI	Electric Power Research Institute
FIPS	Federal Information Processing Standards
G	Generation
GIS	Geographic Information System
IEC	International Electrotechnical Commission
IECSA	Integrated Energy and Communications Systems Architecture
IED	Intelligent Electronic Device
IEEE	Institute for Electrical and Electronics Engineers
IP	Intellectual Property
IP	Internet Protocol
ISO	Independent System Operators
IT	Information Technology
LMP	Locational Marginal Pricing
MAIFI	Momentary Average Interruption Frequency Index
NEP	National Energy Policy
NRECA	National Rural Electric Cooperative Association
NREL	National Renewable Energy Laboratory
NTGS	National Transmission Grid Study

O&M	Operating and Management
OETD	Office of Electric Transmission and Distribution
PLC	Programmable Logic Controller
PNNL	Pacific Northwest National Laboratory
PQ	Power Quality
R&D	Research and Development
RD^3	Research, Development, Demonstration, and Deployment
RDF	Resource Description Framework
RFID	Radio-Frequency Identification
RTO	Regional Transmission Organizations
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SBIR	Small Business Innovative Research
SCADA	Supervisory Control and Data Acquisition
SNMP	Simple Network Management Protocol
STTR	Small Business Technology Transfer
T	Transmission
T&D	Transmission and Distribution
TC	Technical Committee
UCA	Utility Communications Architecture
UML	Unified Modeling Language
VAR	Volt-Amps-Reactive
XML	Extensible Markup Language

Appendix A

Agenda for the DOE Electric Distribution Multi-Year Research, Development, Demonstration, and Deployment (RD^3) Technology Roadmap Workshop, August 2004

Electric Distribution Multi-Year Research, Development, Demonstration, and Deployment (RD^3) Plan Workshop

8:00 AM, Tuesday, August 17 – 4:00 PM, Wednesday, August 18

	Tuesday, August 17	Wednesday, August 18
7:00		
8:00		
9:00	**Registration & Breakfast**	**Breakfast**
10:00	**Plenary Session at ComEd Commercial Center Auditorium**	**Concurrent Breakout Sessions** (Continued)
11:00		
12:00	**Lunch**	**Lunch**
1:00	**Concurrent Breakout Sessions** ▪ Architecture & Communication Standards ▪ Monitoring & Load Management Technologies ▪ Advanced Distribution Technologies & Operating Concepts ▪ Modeling & Simulation	**Wrap-Up Session**
2:00		
3:00		
4:00		
5:00		
6:00		
7:00	**Reception at The Wyndham Drake Hotel**	
8:00		
9:00		

Electric Distribution Multi-Year Research, Development, Demonstration, and Deployment (RD^3) Plan Workshop

8:00 AM, Tuesday, August 17 – 4:00 PM, Wednesday, August 18

Exelon Business Resource Center
2011 Swift Drive, Oak Brook, IL 60523 (630-684-3500)

Tuesday, August 17, 2004

8:30 – 9:00 Registration and Continental Breakfast

9:00 –11:30 **Plenary Session** (ComEd Commercial Center Auditorium, adjacent to Exelon Center)

- ***Welcome and Utility Perspectives of Electric Distribution RD^3 Needs***
  Dave DeCampli, Vice President, Asset Management, Exelon
- ***Overview of the U.S. Department of Energy (DOE) Office of Electric Transmission and Distribution (OETD) R&D Programs***
  Gilbert Bindewald, Manager, Transmission & Distribution Integration, DOE
- ***Electric Distribution RD^3 Needs***
  Dave Nichols, Manager, Corporate Technology Development, American Electric Power
- ***Overview of the US DOE Electric Distribution and GridWise Programs***
  Eric Lightner, Program Manager, DOE

11:30 – 12:30 LUNCH (Provided at Exelon Center)

12:30 – 5:00 **Concurrent Breakout Sessions**

Session 1	Session 2	Session 3	Session 4
Architecture & Communication Standards	**Monitoring & Load Management Technologies**	**Advanced Distribution Technologies & Operating Concepts**	**Modeling & Simulation**
Co-chairs: Ron Ambrosio, IBM Homer Cotton, Southern Company	*Co-chairs:* Matt Donnelly, PNNL Doug Fitchett, American Electric Power	*Co-chairs:* Jim Crane, Exelon Jonathan Lynch, Northern Power	*Co-chairs:* Richard Seguin, DTE Energy Devin Van Zandt, GE

SESSION BREAK: 2:30 – 3:00

Each session will be facilitated by two co-chairs to identity and define the top-five-priority RD^3 activities. Discussions will encompass the following key topic areas:

- The problems to be addressed, and the end state of each problem once addressed
- Specific technology needs and their performance requirements
- Current science and technology capabilities
- Existing capability gaps (between current and needed states) and barriers
- Prioritization of capability gaps in need of an RD^3 activity
- Consensus of the top-five RD^3 activities in each session
- Investment horizon, i.e., near- (1-2 years), mid- (3-5 years), or long- (beyond 5 years) term, recommended for each top-five RD^3 activity
- Development strategy and performance targets with associated schedules

6:30 –8:00 Reception (Wyndham Drake Hotel, Oak Brook, IL 60523, 630-574-5700)

Wednesday, August 18, 2004

9:00-11:30 **Concurrent Breakout Sessions** (Continued)

Session 1	Session 2	Session 3	Session 4
Architecture & Communication Standards	**Monitoring & Load Management Technologies**	**Advanced Distribution Technologies & Operating Concepts**	**Modeling & Simulation**
Co-chairs: Ron Ambrosio, IBM Homer Cotton, Southern Company	*Co-chairs:* Matt Donnelly, PNNL Doug Fitchett, American Electric Power	*Co-chairs:* Jim Crane, Exelon Jonathan Lynch, Northern Power	*Co-chairs:* Richard Seguin, DTE Energy Devin Van Zandt, GE

Discussions continue to reach the top-five-priority RD^3 activities in each session. For each top-five R&D activity, a summary presentation will be prepared and presented by a designated champion during the ensuing wrap-up session.

11:30 – 12:30 LUNCH (Provided at Exelon Center)

12:30 – 4:00 **Wrap-Up Session**

Individual breakout session presentations (one session after the other), including:

- Presentation by the co-chairs on the overall problems/needs/technologies landscape covered and the discussion process leading to the consensus top-five RD^3 activities
- Presentations by each of the five champions on the session's consensus top-five RD^3 activities, summarizing the key aspects of discussion defined under the Breakout Session Agenda

Closing Remarks and Next Steps
Eric Lightner, Program Manager, DOE

Appendix B

Attendance List of the DOE Electric Distribution Multi-Year Research, Development, Demonstration, and Deployment (RD^3) Technology Roadmap Workshop, August 2004

Electric Distribution Multi-Year Research, Development, Demonstration, and Deployment (RD^3) Plan Workshop Attendee List (8/17-18/04)

Architecture and Communication Standards

Name	Organization
1. Ron Ambrosio (co-chair)	IBM Research
2. Thomas Basso	NREL
3. Chris Campbell	Connected Energy Corp
4. Homer Cotton Jr. (co-chair)	Southern Company
5. Richard Drummond	Drummond Group
6. Herman Fletcher	Cooper Power Systems
7. Erich Gunther	Enernex
8. Joe Hughes	EPRI
9. Ali Ipakchi	Areva T&D Automation
10. Mauricio Justiniano (recorder)	Energetics Inc.
11. Mladen Kezunovic	Texas A&M University
12. Kristen Law	Honeywell
13. Terry Mohn	San Diego Gas and Electric
14. Peter Sanza	GE Global Research
15. Mark Simon	Exelon
16. Steve Windergren	PNNL
17. Eric Wong	Cummins Power Generation
18. Bob Yinger	Southern California Edison

Monitoring and Load Management

Name	Organization
19. Carl Benner	Texas A&M
20. Bill Buettner	Schneider Electric
21. Frank Doherty	Con Edison
22. Matt Donnelly (co-chair)	Pacific Northwest National Laboratory
23. Tara Faherty (recorder)	Energetics, Inc.
24. Doug Fitchett (co-chair)	American Electric Power
25. Renee Guild	AREVA T&D
26. Mike Hoffman	Bonneville Power Administration
27. John Kennedy	Georgia Power
28. Matt Lambdin	Exelon
29. Mark McGranaghan	EPRI-PEAC
30. Dave Nichols	American Electric Power
31. Steve Pullins	Science Applications International Corporation
32. Chris Riggs	Telvent
33. George Rodriguez	Southern California Edison
34. Paul Wang	Concurrent Technologies Corporation
35. Rui Zhou	General Electric

Advanced Distribution Technologies and Operating Concepts

Name	Organization
36. Poonum Agrawal	DOE
37. Gil Bindewald	DOE
38. Dan Brewer (recorder)	Energetics
39. Sunil Cherian	Spirae
40. David Cohen	Infotility
41. Dave Costyk	DTE Energy
42. Jim Crane (co-chair)	Exelon
43. Dick DeBlasio	NREL
44. Luther Dow	EPRI
45. Duane Gilbert	Telvent
46. Frank Goodman	EPRI
47. Stephanie Hamilton	SCE
48. Landis Kannberg	PNNL
49. Soorya Kuloor	Optimal Technologies
50. Frank Lambert	NEETRAC
51. Jonathan Lynch (co-chair)	Northern Power Systems
52. Mike Pearman	Southern Company
53. Michael Pehosh	NRECA
54. Tom Rizy	ORNL
55. Michael Sheehan	MicroPlanet Ltd.
56. Forrest Small	Navigant Utility Forum
57. John Stevens	Sandia National Laboratory
58. Joseph Waligorski	First Energy
59. Randy West	Encorp
60. Ron Willoughby	Cooper Power Systems
61. Sam Ye	GE Research

Modeling and Simulation

Name	Organization
62. Robert Broadwater	Virginia Tech
63. John Dalton	Duke Power
64. Steve Hauser	Gridwise Alliance
65. Bob Jones	Energy & Environmental Enterprise
66. John Kelly	Gas Technology Institute
67. Ben Kroposki	NREL
68. Wayne Manges	ORNL
69. Larry Makal	Raytheon
70. Brian Marchionini (recorder)	Energetics, Inc
71. Laurentiu Nastac	CTC
72. Philip Niedzielski-Eichner	Resource Consultants, Inc.

Modeling and Simulation (continued)

73. Dana Parshall	First Energy
74. Rob Pratt	PNNL
75. William Premerlani	GE
76. Dennis Ray	PSERC
77. Rich Seguin (co-chair)	DTE
78. Mark Swindall	Southern Company
79. Devin Van Zandt (co-chair)	GE Energy
80. Kris Zadlo	Calpine

Unassigned

81. Dave Decampli	Exelon
82. Eric Lightner	DOE
83. Joe Mavec	DOE-Chicago